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# Coalbed Methane in the San Juan Basin of Colorado and New Mexico


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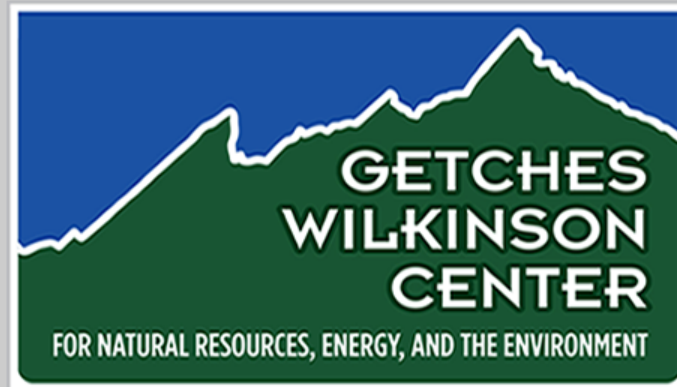
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## COALBED METHANE DEVELOPMENT IN THE INTERMOUNTAIN WEST:

### CASE STUDIES

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*Coalbed methane resources are primarily found in several intermountain states as well as in the Midwest and South. Each CBM basin reflects a different set of environmental, production, and regulatory issues. Surface land owner/subsurface mineral owner relationships, the volume and location of gas, the characteristics of water produced during extraction, state and local legal requirements, and other issues vary considerably. Case studies allow an in-depth exploration of these issues, but if the studies are structured similarly, they also allow for some cross-basin observations. The two case studies presented below examine in detail the San Juan Basin in Colorado and New Mexico and the Powder River Basin in Wyoming and Montana using a similar framework so the analyses and results can be compared and contrasted. The San Juan is a mature, well-developed CBM play that has been the leading source of CBM in the nation. In the San Juan region in Colorado, much of the tension has centered on conflicts between developing energy resources and preserving lands for residential use, recreation, roadless areas, and other goals, and possible impacts of development on drinking water quality. In contrast, the Powder River region is still in the early stages of development and is rapidly growing. Tension has resulted from a different set of conflicts over competing uses of the land, including energy development and ranching, and over the impacts of the produced water on local ecosystems and watersheds. Each case study provides an overview of the basin, a review of its energy and other resources, and an assessment of the tradeoffs between CBM development and important public values.*

#### COALBED METHANE IN THE SAN JUAN BASIN OF COLORADO AND NEW MEXICO

CATHERINE CULLICOTT, CAROLYN DUNMIRE, JERRY BROWN, CHRIS CALWELL, *Ecos Consulting*

#### SUMMARY

The San Juan Basin is a historic oil and gas producing province in the Four Corners region of Colorado and New Mexico. In the 1980s a combination of tax credits and new technologies led to the development of a new resource in the Basin, coalbed methane. In the past 14 years production has increased exponentially in both the Colorado and New Mexico portions of the Basin, and legislation in both states is moving forward in both states to double the density of wells. This proposed infill drilling has prompted local Bureau of Land Management offices to initiate a series of Environmental Impact Statements/Resource Management Plans, two in Colorado and one in New Mexico. This infill drilling could potentially double the number of coalbed methane wells in the Basin over the next 20 years, with at least 4000 more wells being drilled in that time. This is in addition to the already 25,000 total oil, gas, and coalbed methane wells in the Basin, and the expected 12,500 more in the next 20 years. The San Juan Basin has already produced approximately 8.9 trillion cubic feet (tcf) of coalbed methane, and contains an estimated

10–30 more tcf of technically recoverable coalbed methane resource (4–12 tcf economically recoverable at today's gas prices). The most frequently cited “gas-in-place” resource of the San Juan Basin is 50 tcf.

This level of growth in development has significant impacts to the land and communities, but the picture is further complicated by the nature of the governance in the Basin. The San Juan Basin spans two states, three BLM districts, two national forests, four Indian reservations, and six counties, plus private land, two wilderness areas, a National Historic Park and a National Monument. Each level of government has its own regulations affecting the oil and gas industry, which affects the final impacts to the land of the development.

Thirteen different issues/resources with the potential to be impacted by coalbed methane development in the San Juan Basin, including surface and groundwater impacts, split estate lands, communities, effects at the outcrop, and a Forest Service roadless area, further complicate the picture. Each impact can vary in intensity depending on how well planned and executed the devel-



opment is, which depends in large part on the company that does the development. Approximately 90 different companies have coalbed methane operations in the San Juan Basin, and while some, such as BP, win awards for environmental stewardship, others are repeatedly fined for breaking environmental regulations.

Although there is no doubt that the coalbed methane resource of the San Juan Basin will continue to be developed, it is the hope of area residents (ranchers, hunters, recreationalists, and the environmental community, among others) that the energy resource will be developed in a manner that minimizes impacts to the non-energy resources of the area.

## I: SAN JUAN BASIN OVERVIEW

### INTRODUCTION

The San Juan Basin is a major oil and gas-producing province located in the southeastern corner of the Colorado Plateau in Colorado and New Mexico (Figure 1). Oil and gas production has been occurring in the San Juan Basin since the 1920s. Until the last 20 years, this production has tapped conventional oil and gas resources. However in 1976, Amoco drilled a well that would change the focus of oil and gas development to a new resource,

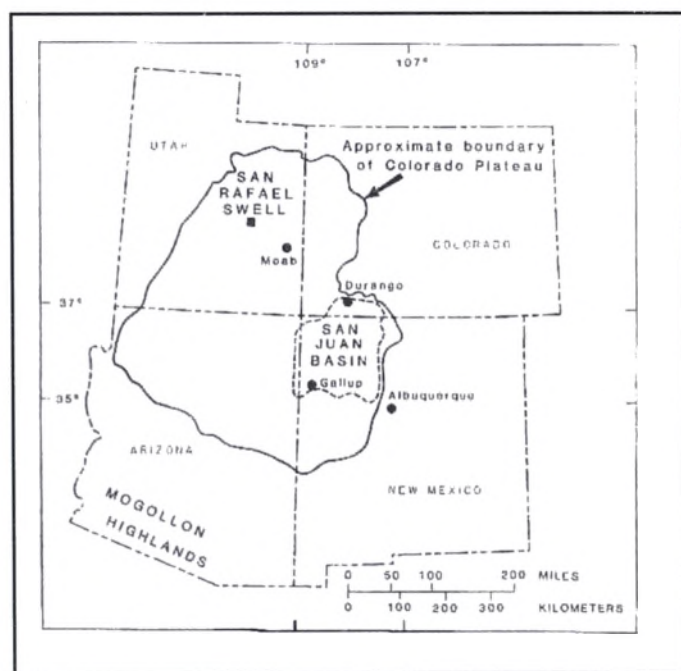


FIGURE 1 Location map showing the San Juan Basin and Colorado Plateau.<sup>1</sup>

coalbed methane. This chapter presents an overview of issues surrounding coalbed methane development in the San Juan Basin, starting with a brief introduction to coalbed methane as a resource.

## COALBED METHANE, THE RESOURCE

### INTRODUCTION

Much has been written about coalbed methane in recent years. There is increased interest in natural gas generally, because it burns more cleanly than oil or coal. There are abundant reserves of it available within the U.S. and Canada, avoiding the energy security concerns that plague oil. Perhaps most importantly, it is versatile. It can be burned directly onsite at homes and businesses for space heating and water heating, used directly by power plants for generating electricity, and offers significant promise as a transportation fuel (either directly or as a means of producing hydrogen for fuel cells). Methane is the major component of natural gas, so coalbed methane can be used in the same manner as so-called "conventional" natural gas. The recent development of technology specifically aimed at recovering methane from coal seams has led to a boom in production of coalbed methane over the past 15 years. Figure 2 shows areas of the country where this boom in development is occurring. The issues and impacts of developing this resource will be discussed further in Section 2.

### CONVENTIONAL NATURAL GAS

Coalbed methane is considered to be an unconventional resource because it is neither formed nor extracted in the same manner as conventional oil and gas. Conventional oil and gas form from source oceanic rocks (shale, limestone) that contain a high percentage of organic (carbon-containing) material originating from microscopic sea creatures. When this organic matter is subjected to the right increased pressure/temperature conditions (referred to commonly as the oil window), liquid and gaseous hydrocarbons are generated. These hydrocarbons are less dense and more buoyant than the surrounding rocks, and therefore migrate upward until they are trapped by some sort of geologic feature such as a fault or fold. They are then stored in the rock (known as the "reservoir rock") under the trap. The oil and gas are trapped in pore spaces within the reservoir rock. This combination of source rock, reservoir



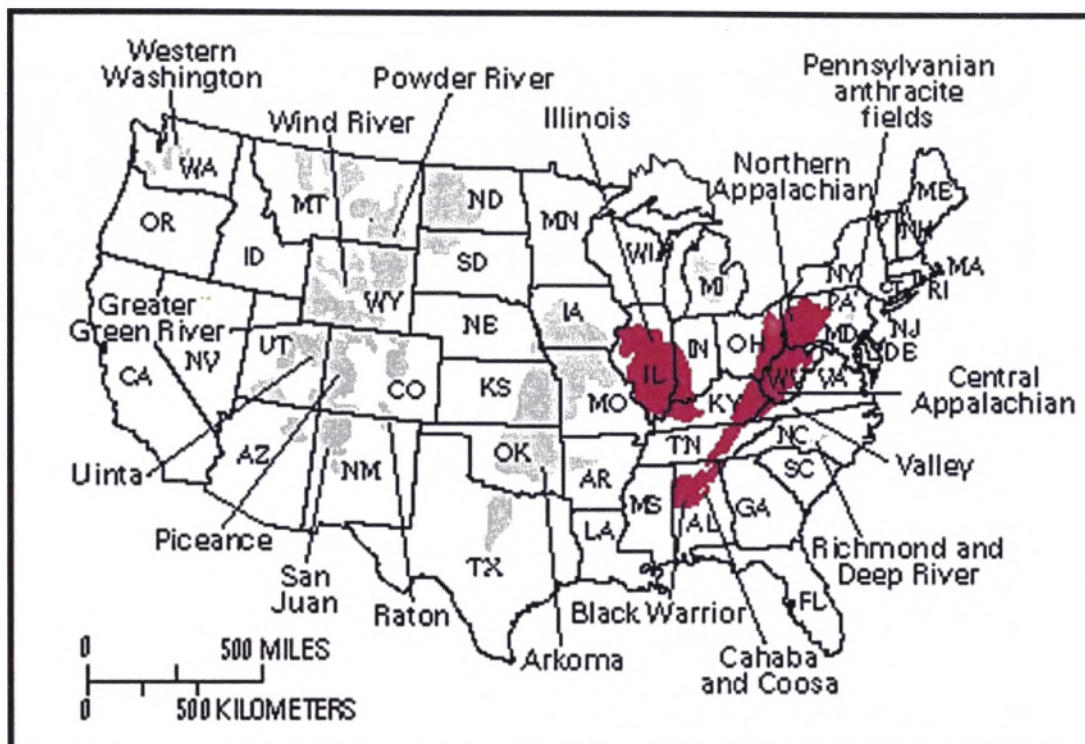


FIGURE 2 Areas within the U.S. with coalbed methane development and/or potential.<sup>2</sup> Areas colored red are basins that emit significant amounts of coalbed methane to the air as a result of coal mining.

rock, and trap rock is necessary in order for a conventional oil and gas deposit to exist. Because the traps are not generally discernable from the surface, complex exploration strategies are utilized by production companies, including seismic, gravity, and magnetic surveys.

#### COALBED METHANE

Coalbed methane deposits differ from conventional oil and gas deposits in several ways. Coal-bed gas is present in all coal beds and is formed by biochemical and physical processes during the conversion of accumulated plant material into coal. First, the coal is both the source rock and reservoir rock of the methane, and water within the coal seam is the trap. Second, the coal that generates the methane formed in swampy areas on land, so the source of the organic matter is plant material rather than animal material. Third, when the plant material is subjected to increased heat and pressure (diagenesis), the organic material undergoes chemical and physical changes and turns into coal without moving from the original point of deposition, except for compaction. On average it takes about ten feet of peat/original plant material to form one foot of coal.<sup>3</sup> The methane within the coal is generated

by either microbial (biogenic) or thermal (thermogenic) processes shortly after burial and throughout the diagenesis that results from further burial.<sup>4</sup> Fourth, the methane is not just occupying pore spaces within the coal, but is in fact adsorbed or accumulated on the surface of the coal. Water contained in fractures (cleats) in the coal exerts enough pressure on the coal to keep the methane in place. This means that when the coal seam is tapped with a well, gas will generally not flow until after the

water has been removed from the coal seam. Removal of the water releases pressure on the coal, and if the coal is sufficiently fractured, release of the water pressure allows the methane to escape (Figure 3). As more water is removed, more methane desorbs (releases) from the coal (Figure 4). According to the USGS, one short ton of coal can produce as much as 46,000 cubic feet of methane.<sup>5</sup> Coal can hold two to three times as much gas in place as conventional sandstone reservoirs.<sup>6</sup> The San Juan Basin coals contain approximately 100 to 500 cubic feet of gas per ton of coal,<sup>7</sup> in different seams throughout the Fruitland Formation.

#### SAN JUAN BASIN—GEOLOGIC SETTING

The San Juan Basin is a major gas and oil-producing province located in the southeastern corner of the Colorado Plateau (Figure 1). The basin has an elliptical shape, and at its longest is about 100 miles (north-south) by 90 mile (east-west), covering an area of about 7,100 square miles (4.54 million acres).<sup>9</sup> The San Juan Basin is a large bowl in the bedrock that was filled up over the past 500 million years with more than 14,000<sup>10</sup> feet of



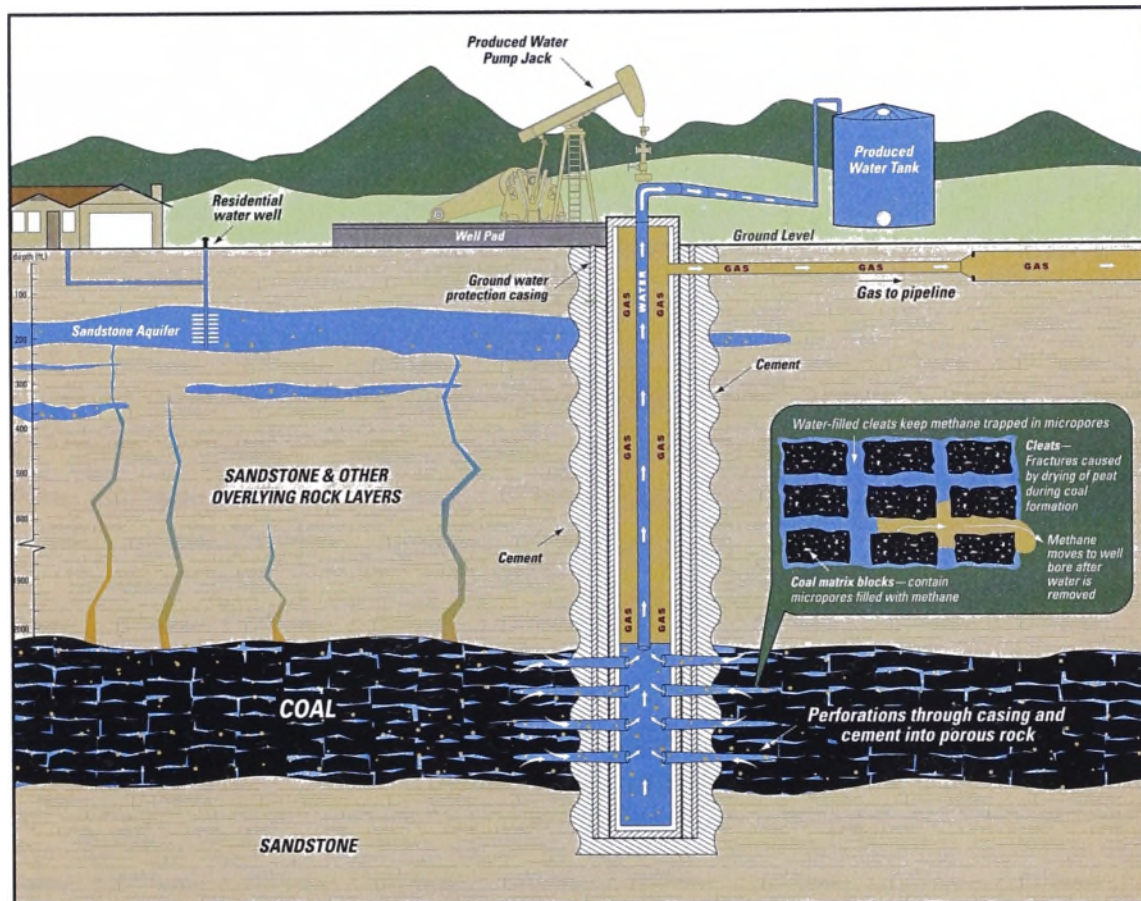


FIGURE 3 overleaf: Illustration of a hypothetical coalbed methane well, showing detail of coal seam, how water removal causes gas release, gas transport pipes, and aboveground well site equipment (produced water pumpjack, produced water tank).

sedimentary rocks such as sandstone, limestone, shale, and coal. Extractable accumulations of hydrocarbons exist at many different depths in the San Juan Basin, including conventional gas and oil in the Mesa Verde Group at over 5,000 feet deep, and conventional gas in the Dakota

Formation at over 8,000 feet deep.<sup>11</sup> Coalbed methane occurs in two different formations within the San Juan Basin, the Fruitland Formation, with average depth 2,000 feet, and the deeper, older Menafée Formation within the Mesa Verde Group.

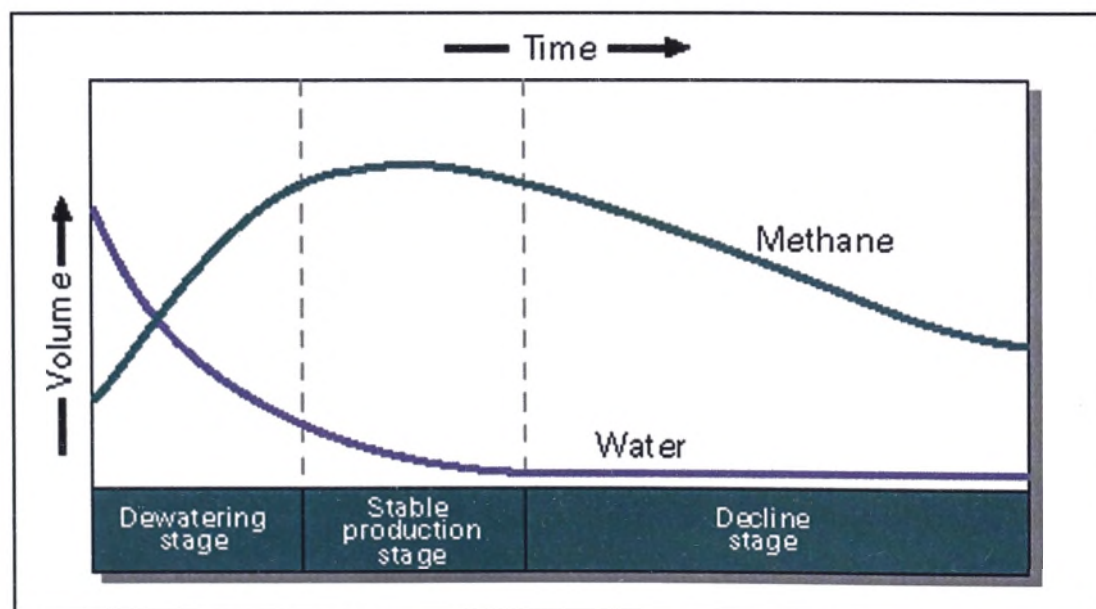


FIGURE 4: Water and gas production versus time for a typical coalbed methane well.<sup>8</sup>



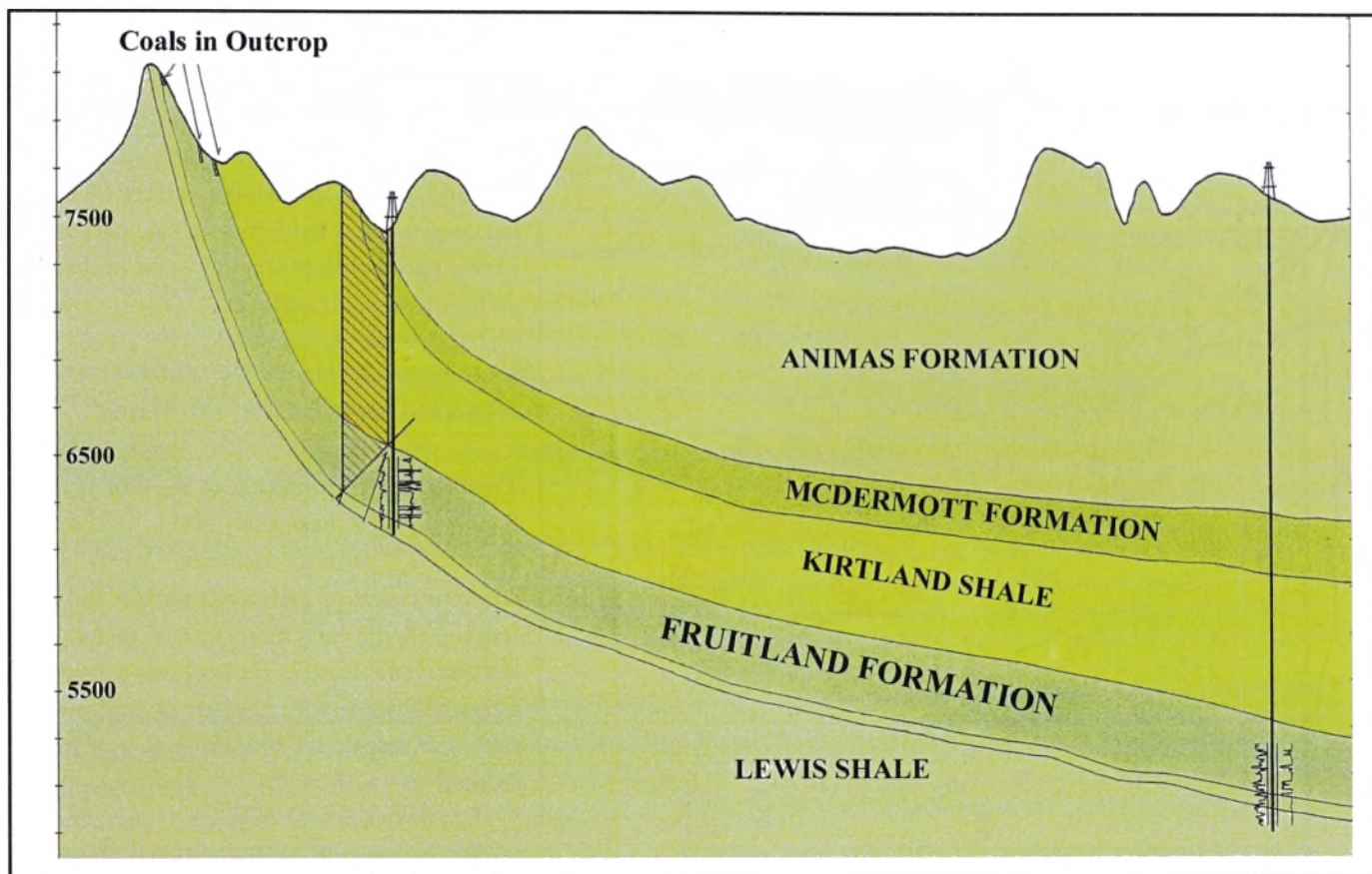


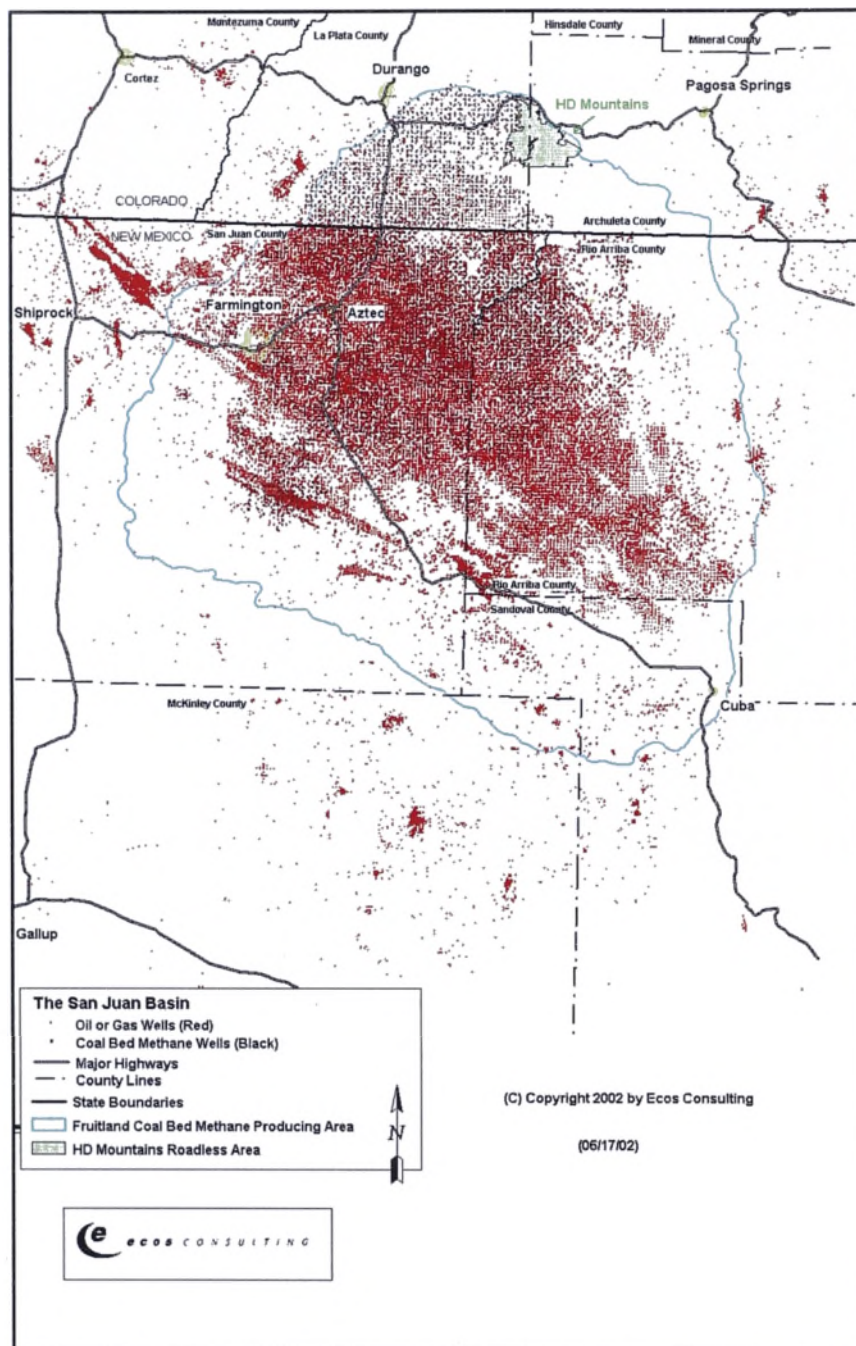
FIGURE 5 Cross section through Hogback Monocline along Pine River, La Plata County, Colorado, showing the Fruitland Formation at depth below the ground surface and the fold that warps the formation up to the surface. Vertical scale exaggerated five times relative to horizontal scale.<sup>15</sup>

The vast majority of the coalbed methane resource currently being developed in the San Juan Basin is contained within the Cretaceous Fruitland Formation. The organic plant material that formed the coal was deposited in swamps that flourished for millions of years. In the time since the plant material was deposited, the western interior of North America has undergone a series of mountain building and other tectonic events during which the basin itself was formed, the Hogback Monocline, which delineates the northern and western edges of the Basin, was formed,<sup>12</sup> and the Colorado Plateau, containing the San Juan Basin, was uplifted as a coherent block.<sup>13</sup> Additional sedimentary rocks were deposited on top of the Fruitland during this time period.

Within the San Juan Basin, the Fruitland crops out (*i.e.* is exposed at the surface) around the periphery of the basin and at its deepest is a little more than 4,000 feet below the surface in several areas in the northeast part.<sup>14</sup> The Hogback Monocline fold (Figure 5) warps the

Fruitland from depths of greater than 3,000 feet to the surface over a horizontal distance of, in many cases, fewer than five miles. Since the methane is produced directly from the coal, it is found exactly where coal is found. The outcrop of the Fruitland marks the limits of coalbed methane production from the Fruitland Formation in the San Juan Basin, so no coal bed methane wells are found beyond it. Figure 6 shows the outline of the outcrop of the Fruitland Formation relative to towns, roads, and county and state lines. Also shown on Figure 6 are the over 25,000 wells (oil, conventional gas, and coalbed methane) that were drilled in the San Juan Basin between 1921 and 1995.





## SAN JUAN BASIN—NON-ENERGY RESOURCES

The Basin's non-energy resources are extensive and varied, spanning a variety of national forests, wilderness areas, national parks, national monuments, state parks, and reservations (table 1).

## COALBED METHANE DEVELOPMENT IN THE SAN JUAN BASIN—HISTORY

The Fruitland Formation of the San Juan Basin contains more than 200 billion tons of coal,<sup>16</sup> <sup>17</sup> with an estimated 50 trillion cubic feet (tcf) of gas stored within the coal itself.<sup>18</sup> In the early years of coal mining in the Basin, methane in the coal was considered a hazardous nuisance because of explosions, fires, gas seeps, and contamination of water wells.<sup>19</sup>

The development of coalbed methane in the Fruitland Formation of the Northern San Juan Basin in Colorado began in earnest in the late 1980s,<sup>20</sup> however, natural gas from a coal seam may have been tapped as long as 100 years ago. The first recorded coalbed methane well was drilled in 1951 when the Stanolind Oil and Gas Company drilled into the Fruitland Formation just outside of Ignacio, Colorado.<sup>21</sup> For the next 20 years, though, drilling targeted shallow gas within Fruitland Formation sandstones (see Figure 3) rather than the Fruitland coals. In 1977, Amoco, the successor to Stanolind, drilled what is considered to be the CBM discovery well for the San Juan Basin, Amoco Cahn Gas Com No. 1, just south of the state line in New Mexico.<sup>22</sup>

The most prolific well in the region to date is Amoco's Gardner A-1 well, which has produced over 20 billion cubic feet of gas. Cumulative production of coalbed methane to date from the San Juan Basin is about 8.9 trillion cubic feet.<sup>23</sup>

FIGURE 6 Map of San Juan Basin, showing towns, roads, and county and state lines. The red dots are some of the 25,000 conventional oil and gas wells that were drilled in the San Juan Basin up through 1995, and the black dots are coalbed methane wells drilled in the same time period



TABLE 1 NON-ENERGY RESOURCES IN THE SAN JUAN BASIN

Type of Resource	Examples
Environmental	San Juan National Forest, Colorado HD Mountains roadless area, Colorado Carson National Forest, New Mexico Bisti / De-Na-Zin Wilderness, New Mexico San Juan River Watershed (Upper Colorado River Drainage)— San Juan, Animas, La Plata, Los Pinos, and Chaco Rivers, Largo Canyon, Colorado and New Mexico
Archaeological/ Cultural	Chaco Culture National Historic Park, New Mexico Aztec Ruin National Monument, New Mexico Salmon Ruins and Heritage Park, New Mexico Southern Ute Indian Reservation, Colorado Ute Mountain Indian Reservation, Colorado Jicarilla Apache Reservation, New Mexico Navajo Indian Reservation
Recreational	Angel Peak National Recreation Site, New Mexico Bisti Wilderness, New Mexico Navajo Lake State Park, New Mexico
Biological	Bald eagles, elk, mule deer, black bear, rare plants in HD Mountains roadless area and other portions of San Juan Basin in Colorado. Southwest Willow Flycatcher—threatened and endangered bird species.

**WHAT IS A TCF?**

1 trillion (1,000,000,000,000) cubic feet of natural gas is a quantity that can be difficult to comprehend. Total U.S. consumption of natural gas in 2000 was approximately 22 tcf, according to the U.S. Department of Energy's *Natural Gas Annual 2000*. In the residential sector, natural gas is used primarily for cooking and space and water heating. Average annual residential usage is about 50,000 cubic feet per household, so 1 tcf of natural gas is enough to meet the nation's residential gas needs for approximately 75 days. At present rates of growth in demand, U.S. natural gas consumption is expected to exceed 30 tcf in 2011, according to the U.S. Department of Energy's *Annual Energy Outlook 2000–2015*. So, simply put, 1 tcf is approximately the annual growth in U.S. demand for natural gas.

**COALBED METHANE PRODUCTION IN THE SAN JUAN BASIN—CURRENT STATUS**

The growth in production of coalbed methane from the San Juan Basin in the past 14 years has been tremendous, as shown in Figure 7 and Figure 8, below. There are currently 2,850 coalbed methane wells in the New Mexico portion of the San Juan Basin and 1,200 wells in the Colorado portion, on lands underlain by federal minerals alone.<sup>24</sup> There are an additional 158 wells in the New Mexico portion of the San Juan Basin on leases owned by non-federal mineral rights holders.<sup>25</sup> Production through coal seam gas processing plants averaged 1.835 billion cubic feet per day (bcf/d) for the year 2000. Gas from the San Juan Basin was delivered to El Paso Natural Gas, Transwestern, and PNM (Public Service Company of

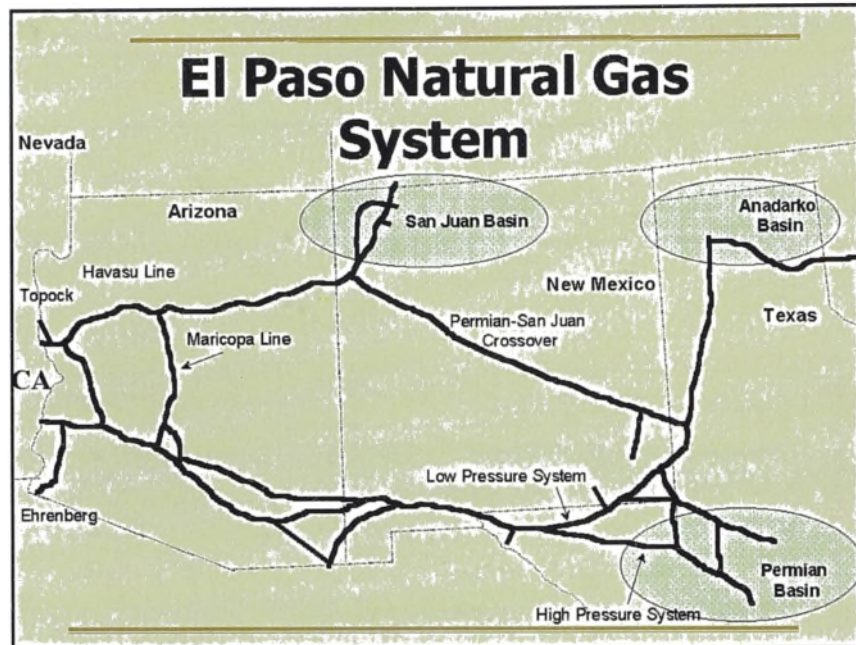


FIGURE 7 El Paso Natural Gas southwest pipeline system, showing San Juan Basin and other southwestern basins.

New Mexico) at a rate of 3.764 bcf/d.<sup>26</sup> They, in turn, operate pipelines that gather gas from other basins in the southwest and route the gas to markets in California (Figure 7). The San Juan Basin is California's largest single supplier of natural gas.<sup>27</sup>

In the past 13 years, coalbed methane production has increased by a factor of 34 in the New Mexico portion of

the Basin<sup>28</sup> (see Figure 8), and that growth is expected to continue. Figure 8 shows the exponential growth of coalbed methane production in the San Juan Basin for the years 1988 through 2001. Production from the New Mexico portion of the basin was steady for the years 1996–1999, and has declined slightly since then. Production from the Colorado portion of the basin has

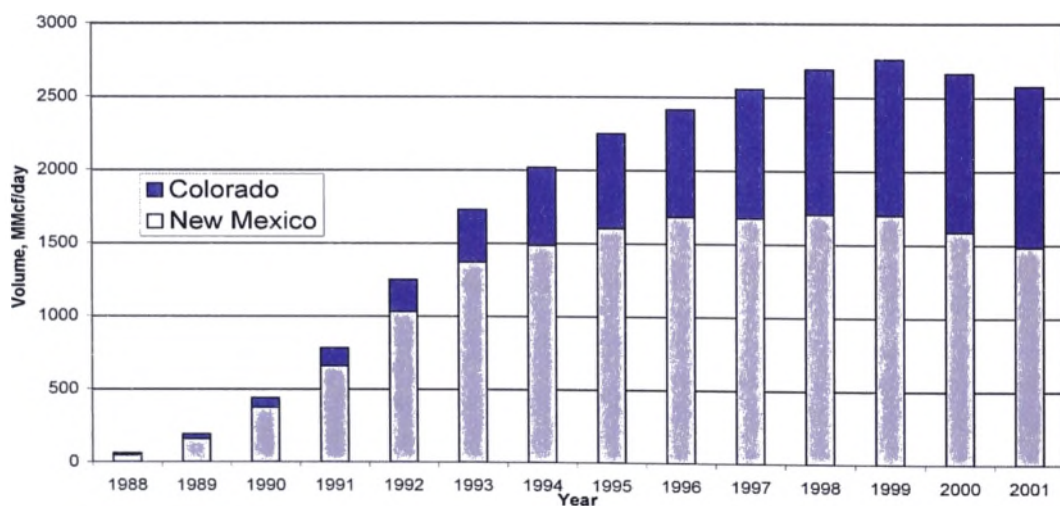


FIGURE 8 Coalbed methane production in the San Juan Basin, New Mexico and Colorado, 1988–2001, in million cubic feet per day (MMcf/d).<sup>29</sup>



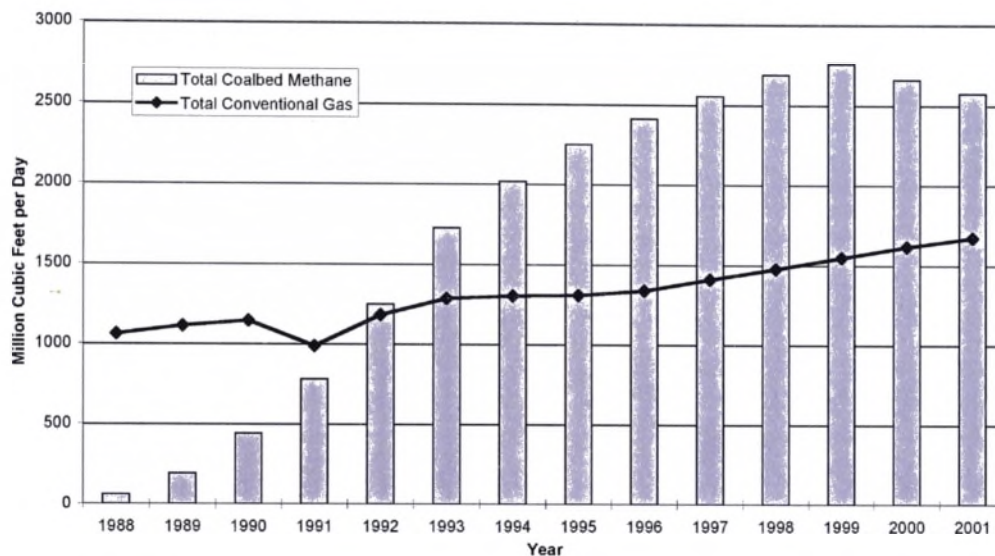


FIGURE 9 Coalbed methane and conventional natural gas production in the San Juan Basin, New Mexico and Colorado, 1988–2001, in million cubic feet per day (MMcf/d).<sup>34</sup>

remained steady for the past three years (1999–2001). Based on the shape of the curve in Figure 8, overall production in the Basin peaked in 1999 and has been slowly decreasing since then.

Figure 9 shows both coalbed methane and conventional gas during the same time period. In Colorado, the volume of coalbed methane produced has been more than ten times the volume of conventional natural gas produced for the past five years. In New Mexico, the volume of coalbed methane produced was more than the volume of natural gas produced for the years 1993 to 1999.<sup>30</sup> In 2000, the volumes were nearly the same, and in 2001, the volume of conventional gas produced exceeded the volume of coalbed methane produced.<sup>31</sup>

The current takeaway capacity of the basin is 4 bcf/d. In 2000 the San Juan Basin produced 0.78 tcf, which was 4% of the United States total natural gas production, and 3% of United States total natural gas consumption.<sup>32</sup> The San Juan Basin produces the majority of coalbed methane in the country compared with other basins. The total value of resources removed from the San Juan Basin in 2000 was \$2.5 billion, of which 12.5%, or \$325 million, was the Federal Royalty.<sup>33</sup> The majority of coalbed methane produced in the basin has been produced in the New Mexico portion, but the Colorado portion is now more than half the amount that New Mexico produces. New Mexico's portion of 2000 coalbed methane pro-

duced was 45% of total New Mexico natural gas production (See Figure 8).

This rapid expansion of development likely would not have occurred without the advent of the Section 29 Tax Credits in 1987. The "Section 29" refers to Section 29 of the *Crude Oil Windfall Profit Tax Act*, signed by President Carter in 1980, which was enacted with the intent to tax a fair share of the added revenues enjoyed by oil companies as a result of high prices.<sup>35</sup> Section 29 of the act "included a tax credit for the production of alternative, or non-conventional, fuels designed to encourage the domestic development of alternative energy supplies."<sup>36</sup> At the time, it was expected that the taxes on crude oil would help support the development of alternative energy sources.<sup>37</sup>

Coalbed methane wells, as an unconventional source of natural gas, qualified for this credit. The credit varies based on market prices, but is approximately \$1 per thousand cubic feet of gas (Mcf). The credit was initially applied to wells drilled in the time period 1988–1990, but was extended through 1992. There was concern within the industry that the expiration of the credit would mean a slowdown of the industry. However, it has remained profitable for companies to continue coalbed methane development in the intervening 10 years, and drilling of new coalbed methane wells has continued, albeit at a slower pace than before 1992 (Figure 10). Indeed, the coalbed methane industry in both Colorado

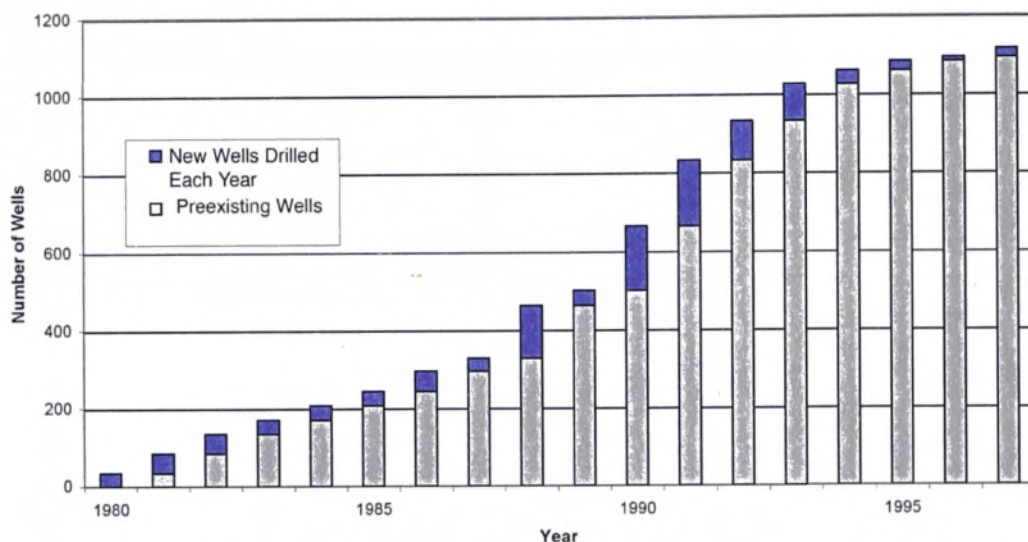


FIGURE 10 Coalbed methane wells drilled in the La Plata County, Colorado, portion of the San Juan Basin, 1980–1997,<sup>40</sup> showing new wells drilled each year and cumulative number of wells drilled.

and New Mexico wants to double the density of coalbed methane wells over the next 10 years. The Section 29 tax credit was good for ten years after the drilling date, which means that there are some wells today that are still garnering this credit with today's average gas price of \$2.25/Mcf.<sup>38</sup> The current version of the House of Representatives' Energy Plan, H.R. 4, includes reinstating the Section 29 tax credit for coalbed methane.<sup>39</sup>

#### COALBED METHANE PRODUCTION IN THE SAN JUAN BASIN—FUTURE

##### INTRODUCTION

The Farmington Field office of the BLM anticipates approximately 12,500 total new wells (oil, gas, and

coalbed methane) to be drilled in the San Juan Basin over the next 20 years, with 3,000 new coalbed methane expected in just the New Mexico portion of the Basin.<sup>41</sup> Approximately 10,000 of these wells are expected to be drilled on lands with federally administered mineral rights.<sup>42</sup> The wells will be drilled on a combination of leases with currently producing wells through infill drilling, and on currently undeveloped leases. Infill drilling, installing wells on 160 acre instead of 320 acre spacing, is already occurring in portions of the Basin in Colorado, and the process will be discussed for the New Mexico portion of the Basin at a meeting this summer in Santa Fe.<sup>43</sup> There are currently three environmental impact statements underway that will determine what future coalbed methane development

TABLE 2 ENVIRONMENTAL IMPACT STATEMENTS CURRENTLY UNDERWAY IN THE SAN JUAN BASIN, NEW MEXICO AND COLORADO

Name of EIS Project	Area Covered
<ul style="list-style-type: none"> <li>• Northern San Juan Basin Coalbed Methane Environmental Impact Statement</li> <li>• Southern Ute Environmental Impact Statement</li> <li>• Farmington Area Resource Management Plan</li> </ul>	<ul style="list-style-type: none"> <li>• Colorado portion of San Juan Basin, north of Southern Ute Indian Tribe Reservation</li> <li>• Colorado portion of San Juan Basin on Southern Ute Indian Tribe Reservation</li> <li>• New Mexico portion of San Juan Basin</li> </ul>



will look like in the San Juan Basin (Table 2). Each EIS is summarized briefly below.

#### **NORTHERN SAN JUAN BASIN COALBED METHANE ENVIRONMENTAL IMPACT STATEMENT**

The Colorado portion of the San Juan Basin north of the Southern Ute Reservation has been managed under an earlier resource management plan, with the exception of the HD Mountains Roadless Area, which has been managed according to a 1992 EIS. The oil and gas industry's request for infill drilling<sup>44</sup> of coalbed methane wells, doubling the density of wells from one well per 320 acres to two wells per 320 acres, has prompted the current environmental review. Five alternatives addressing six different land status categories were initially proposed by both the USFS/BLM and an industry working group. These range from a minimum of 118 wells to a maximum of 523 wells. Since the EIS scoping meetings, held in January 2002, and as a direct result of comments made by the public at these meetings, the BLM is developing additional alternatives.<sup>45</sup> This has pushed back the originally scheduled draft EIS publishing date from March to July, 2002. No preferred development alternative is available at this time.

#### **SOUTHERN UTE ENVIRONMENTAL IMPACT STATEMENT**

The Southern Ute EIS is still "in progress", as it has been for many years. The EIS was initially undertaken to evaluate "how best can oil and gas development revenues continue to be received and maximized for benefiting the Southern Ute Indian Tribe while at the same time protecting Tribal lands and the environment from injurious impacts."<sup>46</sup> Infill drilling has already been approved for portions of the reservation, and up to 500 more coalbed methane wells are possible on reservation lands.

#### **FARMINGTON AREA RESOURCE MANAGEMENT PLAN**

The New Mexico portion of the San Juan Basin contains the majority of the land in the basin, and 4 million acres of that land are managed by the Farmington Field Office of the Bureau of Land Management. In August 2000, a notice of intent to conduct the Resource Management Plan (RMP) was posted in the Federal Register. This undertaking is a revision of the current RMP, and is being done to "establish land use management policy for multiple resource uses on approximately 1.5 million

acres of public land and 2.26 million acres of federal mineral resources in the Farmington Field Office<sup>47</sup>" including coalbed methane as well as conventional oil and gas. As part of this process, a 20-year Reasonable Foreseeable Development (RFD) scenario was developed for the BLM by the New Mexico Bureau of Geology and Mineral Resources. The RFD scenario anticipates another 12,461 total wells (oil, conventional gas, coalbed methane) to be drilled in the New Mexico portion of the San Juan Basin in the next 20 years, with an associated 3600 miles of new pipelines and up to 300 new compressor stations required as part of this development, impacting a total of 11,600 acres.<sup>48</sup> Of those wells, it is estimated that approximately 3000 will be coalbed methane wells, or approximately 150 new coalbed methane wells are expected to be drilled each year for the next 20 years.

#### **ROLE OF ASSOCIATED GOVERNMENTS IN DECIDING WHAT FUTURE DEVELOPMENT WILL LOOK LIKE IN THE SAN JUAN BASIN**

There are five layers of government that have jurisdiction in the larger San Juan Basin area: federal, tribal, state, county, and town. Within the Basin are two states, three BLM districts, two National Forests, four Indian Reservations, and six counties, plus private land, two wilderness areas, a National Historic Park and a National Monument. Each plays a role in the coalbed methane discussion, as shown in the table on the next page.



TABLE 3: GOVERNMENTS WITH JURISDICTION OVER LAND IN THE SAN JUAN BASIN

Type	Government Name		Jurisdiction	Function
U.S. Federal	United States Bureau of Land Management	Colorado	Public land in Colorado <i>north of the Southern Ute Indian Reservation?</i>	Administer subsurface mineral rights. Oversee EIS process. Conduct lease sales. Regulate drilling through APD.
		New Mexico	4 million subsurface acres with federal minerals	Administer subsurface mineral rights. Oversee EIS process. Conduct lease sales. Regulate drilling through APD.
	United States Forest Service	Colorado	San Juan National Forest	Identify Forest Service land suitable for oil and gas leasing. Ensure proposed development proceeds consistently with forest RMP.
		New Mexico	Carson National Forest	Identify Forest Service land suitable for oil and gas leasing. Ensure proposed development proceeds consistently with forest RMP.
Tribal	Southern Ute Indian Tribe, Colorado		Southern Ute Indian Tribal Lands	Red Willow Production Company operates 200 wells on tribal land. Red Cedar Gathering operates gathering pipeline on tribal land. Regulates other companies operating on tribal land.
	Ute Mountain Ute Indian Tribe, Colorado		Ute Mountain Ute Tribal Lands	
	Jicarilla Apache Tribe, New Mexico		Jicarilla Apache Tribal Lands	
	Navajo Nation, New Mexico		Navajo Nation Lands	

TABLE 3: GOVERNMENTS WITH JURISDICTION OVER LAND IN THE SAN JUAN BASIN, CONTINUED

Type	Government Name	Jurisdiction	Function
State	Colorado Oil and Gas Conservation Commission	Colorado state lands, direct regulation of development	Promotes responsible development of Colorado's oil and gas natural resources. Approved infill drilling process.
		Federal, private, Indian lands	Approved infill drilling process and well locations.
	New Mexico Oil Conservation Division, District 3	McKinley, Rio Arriba, Sandoval, and San Juan Counties	Permitting, well data, inspection, and enforcement actions
County	Archuleta County, Colorado	County land	Developing county rules for oil and gas development
	La Plata County, Colorado	County land	Supports local control of land use through county regulations. Currently producing a report discussing impacts to the county from oil and gas development. Intercedes on behalf of residents impacted by development.
	Rio Arriba County, New Mexico	County land	No role in oil and gas development within the county.
	Sandoval County, New Mexico	County land	No role in oil and gas development within the county.
	San Juan County, New Mexico	County land. Largest percentage of basin within San Juan County	No role in oil and gas development within the county.
City/Town	City of Bayfield, Colorado	City land	Active with residents, industry in well placement decisions within town limits.
	Town of Ignacio, Colorado	Town land	No development within town. However, there are many wells are drilled right outside the town limits, and the town is impacted in several ways by the surrounding development.



TABLE 3: GOVERNMENTS WITH JURISDICTION OVER LAND IN THE SAN JUAN BASIN, CONTINUED

Type	Government Name	Jurisdiction	Function
State	City of Aztec, New Mexico	City land	Recently passed City Ordinance 2001-272, updating the city's rules for oil and gas wells in order to "facilitate the development of oil and gas resources within the incorporated area of the city while mitigating potential land use conflicts between development and existing or planned land uses." Applications to drill are made to the municipality, and the Community Development Department issues recommendations for approval or denial.
City/Town	City of Bloomfield, New Mexico	City land	The city has a permitting process for drilling of wells. The city council does final review of applications then approves the application for permit to drill, and the company may proceed with the drilling. Once the well is drilled, the New Mexico Oil Conservation Division does all monitoring.
	City of Farmington, New Mexico	City land	Requires a special use permit prior to drilling, which is a zoning action that requires a public hearing. The company applies to the city clerk's office for the drilling permit and puts up bonds. The zoning review process checks for compliance with standards for minimum separation between structures, rights-of-way, water, etc., and may require mitigation measures, but all wells are approved.



II: SAN JUAN BASIN RESOURCES

SAN JUAN BASIN ESTIMATED COALBED METHANE RESOURCE

INTRODUCTION

Estimates of the coalbed methane resource in the San Juan Basin vary widely, depending on both the source and type of the estimate. Energy resource estimates come in several forms, presented here in order of decreasing volume. Largest is an estimate of “gas-in-place”, which is simply the theoretical amount of gas that the formation is physically capable of holding. Second is the amount of that gas that is recoverable using current technology, or the “technically recoverable resource”. Finally, even if the gas is technologically recoverable, it might not be economic to extract, so the final category is economically recoverable. The amount economically recoverable depends on the current price of gas. For coalbed methane, about

30 percent of the technically recoverable gas is economically recoverable if gas is priced at \$2 per thousand cubic feet (Mcf). If gas is priced at \$3.34 per Mcf, the economically recoverable amount increases to slightly more than 50 percent.<sup>49</sup>

ESTIMATES

GAS-IN-PLACE

The energy resource number most frequently cited for the San Juan Basin is 50 tcf of gas within the Fruitland Formation alone,<sup>50</sup> a number that has been used to describe the San Juan Basin “resource” of coalbed methane for the past 15 years.<sup>51</sup> This number refers to gas-in-place only (Figure 11). In addition, the gas-in-place estimates for the older, deeper, Menafee Formation range from 34–38 tcf,<sup>52</sup> giving a total Basin gas-in-place estimate of 84–88 tcf. The 84 tcf resource estimate is also cited by the Petroleum Technology Transfer Council.<sup>53</sup>

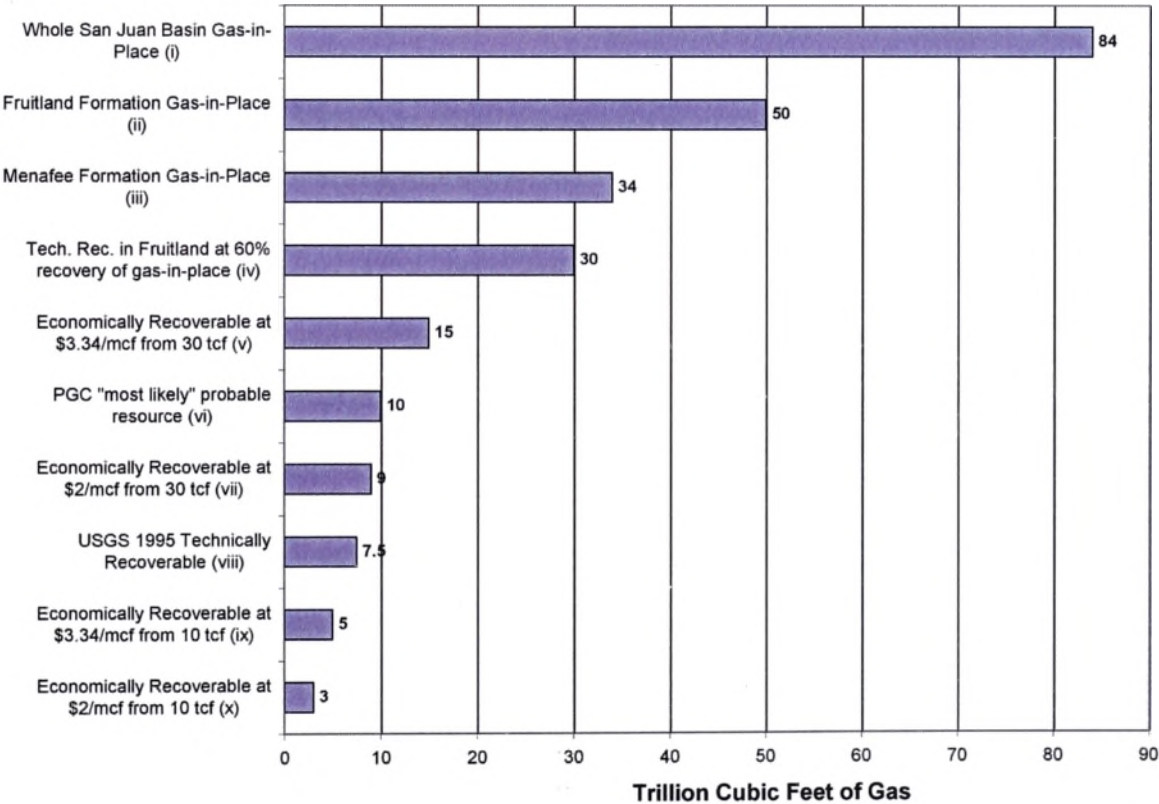


FIGURE 11 Estimates of gas-in-place, technically recoverable, and economically recoverable coalbed methane resources of the San Juan Basin.<sup>57</sup>



#### TECHNICALLY RECOVERABLE

In 1995, the United States Geological Survey estimated the mean technically recoverable amount of coalbed methane in the San Juan Basin at 7.53 tcf.<sup>54</sup> In 2000, the Potential Gas Committee (PGC) estimated the "Probable Resources" of coalbed methane in the San Juan Basin at 10.24 tcf.<sup>55</sup> This category may be reasonably compared with technically recoverable numbers. Therefore, in the intervening five years since the USGS report, the estimated technically recoverable amount of coalbed methane in the San Juan Basin has increased by 36%. However, one source indicates a possible recovery factor of gas-in-place of over 60% when using new technologies,<sup>56</sup> giving a technically recoverable amount for the Fruitland Formation of over 30 tcf.

#### ECONOMICALLY RECOVERABLE

Using the PGC technically recoverable volume of 10.24 tcf and applying the above-mentioned economically recoverable amounts, the San Juan Basin holds between 3.1 tcf (at \$2/mcf) and 5.12 tcf (at \$3.34/mcf) of economically recoverable coalbed methane. Using the 30 tcf technically recoverable estimate cited above gives economically recoverable amounts of between 9 tcf and 15 tcf, respectively. Assuming gas prices remain over \$3/mcf, the actual economically recoverable amount of coalbed methane in the San Juan Basin may be expected to be between 5 tcf and 15 tcf, or approximately 10 tcf.

#### ISSUES SURROUNDING COALBED METHANE DEVELOPMENT IN THE SAN JUAN BASIN:

##### INTRODUCTION

The Northern San Juan Basin Coalbed Methane EIS Proposal dated January 16, 2002, listed the following issues surrounding coalbed methane development: property values, noise, visual impacts, tax revenues, water depletions, surface and groundwater impacts, gas seepage into domestic water wells, dying vegetation at Fruitland outcrop, impacts to wildlife, roadless area in HD's, archaeological resources, and air quality. Additional issues include split estate lands, tax credits, royalties, impacts to rangeland, and effects at the outcrop. These issues largely are Basin-wide, and some or all will be addressed in each of the three Environmental Impact Statements. All are discussed below.



FIGURE 12 Photograph of coalbed methane well and associated infrastructure in the Colorado portion of the San Juan Basin.

#### SPLIT ESTATE LANDS

The term "split estate" refers to land with one owner of the surface and a different owner of the subsurface mineral rights. This situation may arise when an owner sells only the surface land and keeps the subsurface mineral rights. Likewise, it may originate from the time when the land was originally homesteaded and the claimant did not make the trip to the state capital to claim the subsurface mineral rights, which were retained by the government or claimed by other individuals. These competing rights can often lead to conflicts when gas development companies place wells on or adjacent to residential property (Figure 13). Often the surface owner has little say in the process, and can end up with a potentially very noisy well very close to their house (see below). Some production companies are voluntarily developing "surface use agreements" with landowners in order to minimize conflict and impacts and maximize cooperation with regards to well and road siting. Some landowners end up with improved roads and free domestic gas as part of these deals. Others may end up with diminished property values<sup>58</sup> and little if any compensation from industry. One La Plata County, Colorado landowner expressed particular concern to the Durango Herald about a gas company's reluctance to follow its permit requirements for development on his land: "'It's obvious all they're doing is for the bucks,' he said. 'I stand to benefit from the extraction, but I'd just as soon give the money back.'"<sup>59</sup>





FIGURE 13 Photograph of pumpjack and well adjacent to home, Colorado portion of San Juan Basin.

### PROPERTY VALUES

Coalbed methane wells drilled on or adjacent to private land can reduce property values and render land difficult to sell. The development can turn once rural areas into industrial zones. Noise from associated equipment (see below) can heavily impact the residents of the property. In addition, roads, pipeline rights-of-way, power line rights-of-way, and other infrastructure surrounding private land can heavily impact resale value.

### NOISE

Noise is a major concern in areas with coalbed methane development. This noise comes initially from the heavy equipment used to create roads and drill pads, continues at very high levels during drilling and well completion, and becomes a permanent part of the landscape with the installation of pipelines, compressors, pumpjacks, and with the large amount of vehicle traffic needed for routine maintenance. Some noise mitigation measures can be put into place on a well-by-well basis, depending on surface use agreements and applicable government regulations. The Colorado Oil and Gas Conservation Commission (COGCC) has noise regulations in place,<sup>60</sup> however, "currently there are no federal noise standards for oil and gas equipment."<sup>61</sup> The BLM is considering adopting decibel standards, especially near homes<sup>62</sup> and regularly visited archaeological sites in the New Mexico portion of the San Juan Basin.<sup>63</sup>

Lack of regulation can lead to noise levels that can drive people from their homes and change the local atmosphere from rural to industrial. One landowner in Aztec, New Mexico, describes one noise effect of coalbed

methane development as the "compressor nightmare...compressors run night and day. Their constant roar interrupts sleeping and dinner. The companies could muffle the sound if they want, but they never agree to spend the little extra money it would take to make people's lives easier."<sup>64</sup> With regards to a proposed compressor adjacent to her property, one La Plata County, Colorado landowner commented, "I'm just concerned that having this kind of noise behind my home ... would be quite impossible to live with."<sup>65</sup>

Recently in La Plata County, the JM Huber Corporation sought a waiver to noise reduction requirements that were written in to their original 2000 drilling permit, which required that the company used electricity to power any motors needed after the initial six months of drilling. Residents of the subdivision containing the well commented that "the gasoline engine powering the pump was excessively noisy," however company officials stated that measurements taken at the site fall within COGCC standards, and baffles were added to further reduce noise impact.<sup>66</sup> La Plata County denied the waiver, and Huber was directed to install an electric motor pump on the site.

In some cases, however, the wells can be fairly unobtrusive and not very loud once completed, depending on whether compressors and/or pumpjacks are needed. In La Plata County, BP proposed to add compressors to six gas wells, and offered to mitigate the noise with barriers and other measures.<sup>67</sup>

### VISUAL IMPACTS

The visual and aesthetic contrast between a bare well pad, its associated heavy equipment, and the surrounding forest can be stark indeed. Even in the desert, vegetation is stripped away, leaving just bare dirt and equipment. Equally dramatic contrasts can result in residential areas, since even the best paint job cannot cause wellhead equipment to "blend in" with homes, trees, and yards (Figure 14). The "footprint" of such development extends significantly beyond the well pad as well, with roads being cut and pipelines buried to join the wells together. Temporary impacts can be even more profound, as truck





FIGURE 14 Photograph of a well pad with a pumpjack carved into a forest, Colorado.<sup>68</sup>

traffic dramatically increases on rural roads, and massive drill rigs and associated equipment dominate the skyline during well drilling, completion, and workover (the process of redrilling the well to stimulate additional production) (see Figure 15).

It is also clear from some existing coal bed methane wells that the land near well pads can often become degraded, with discarded well fittings, beer cans, fire rings, etc. (Figure 16). It appears, in fact, that the initial decision to allow drilling literally "paves the way" for even greater impacts to the area in the future. This effect has the potential to be particularly devastating in areas such as the HD Mountains roadless area, compromising the pristine quality of the area that made it worth protecting in the first place.



FIGURE 15 Photograph of drilling rig, San Juan Basin, northern New Mexico.



FIGURE 16 Photograph of trash on well pad, New Mexico portion of San Juan Basin.

#### TAX REVENUES/ROYALTIES

In addition to gas production companies, many other entities make money off of coalbed methane development. La Plata County, Colorado, got 42.7% of its property tax revenues from the industry in 2001, a total of 11.7% of total county revenues.<sup>69</sup> The percentage of revenue that the county gets from development has been steadily increasing as the number of coalbed methane wells increases (Figure 17). The federal government received \$211 million from coalbed methane development royalties (12% of revenues) in 2000 from coalbed methane development on federally owned mineral leases in just the New Mexico portion of the San Juan Basin alone.<sup>70</sup> In addition, private subsurface mineral owners get royalties from development, although the industry in the past few months has been challenging the amount of royalties they have to pay private citizens.

Taxes and royalties generated by oil and gas production are a major source of revenue for government and schools in New Mexico. Total natural gas production in New Mexico is in the range of 1.5 trillion cubic feet (tcf) per year.<sup>72</sup> The value of this gas fluctuates with price. For example in 2002, the average gas price is forecasted to be \$2.50 per mcf (thousand cubic feet).<sup>73</sup> Therefore, the total value of natural gas production (assuming 1.5 tcf) will be on the order of \$3.75 billion. The total tax rate on natural gas for school tax, severance tax, conservation tax, and ad valorem taxes on production and equipment is about 7.38% of gross sales value.<sup>74</sup> Therefore, the estimated State tax revenues from natural gas production in



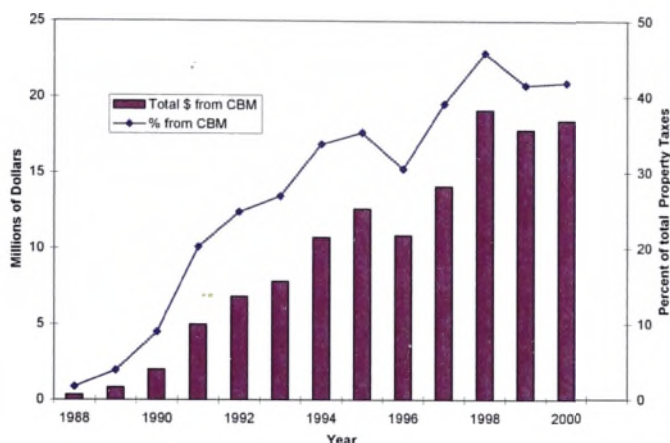


FIGURE 17 *La Plata County property tax revenues from coalbed methane development, dollar amount and as percent of total property taxes, 1988–2000.*<sup>71</sup>

2002 will be on the order of \$275 million. In general, the taxes generated by revenues from natural gas production contribute about 5 to 6% of the total general fund revenues in New Mexico.<sup>75</sup> In addition to tax revenues, New Mexico gains revenue from royalties, lease payments, and bonuses paid by oil and gas companies operating on State and Federal lands.

Private subsurface mineral owners also get royalties from development, although the industry in the past few months has been challenging the amount of royalties they have to pay royalty owners. A July 2001 Colorado Supreme Court decision said that royalty owners should only “bear that portion of the cost of bringing oil and gas to the surface and not to a buyer.”<sup>76</sup> A bill in the Colorado legislature earlier this year would have overturned this ruling, passing along industry’s costs of bringing oil and gas to buyers to royalty owners, thereby reducing their royalty payments, which average about 12% of the sale of the minerals.<sup>77</sup> Many lawmakers on both sides of the aisle felt the bill was necessary because without it, “producers bear all the risk and cost of finding gas and drilling wells” and that producers “deserve to profit.”<sup>78</sup> Those opposing the bill, also from both sides of the aisle, say that the bill “could be devastating for farmers and ranchers who are barely holding on economically. ‘There are 10,000 royalty owners, half farmers and ranchers that need these royalty incomes...we’re talking about potentially hurting thousands of royalty owners to potentially help a few small producers, whom we may not even be helping.’”<sup>79</sup> The bill was passed by the Senate in

February, 2002,<sup>80</sup> and was extremely controversial, leading to editorials,<sup>81</sup> letters to the editor, and royalty owner complaints to the state.<sup>82</sup> The result, for now, was the shelving of the regulation, which will be reconsidered during next year’s legislative session.<sup>83</sup>

#### WATER ISSUES—WATER DEPLETIONS, SURFACE AND GROUNDWATER IMPACTS

Water is the single biggest issue in coalbed methane development, and it is the issue that separates development of this resource from development of conventional resources. Water quantity and water quality can be affected by any number of the steps in CBM development. During drilling of CBM wells, aquifers are crossed by the borehole. Any time an aquifer is breached, cross-contamination may occur. In some instances a surface casing is driven into the ground and filled with concrete before drilling begins in order to form a seal around the borehole in an attempt to minimize contamination of surface aquifers.<sup>84</sup> However, there is no requirement for this degree of protection. Drilling fluids (also known as “mud”<sup>85</sup>) and other rig wastes are often stored in unlined pits (Figure 17), which can allow infiltration of contaminants directly to groundwater. Drilling fluids are necessary for lubricating the drill bit, preventing friction and preventing the drill bit from getting stuck in the hole. According to industry sources, these fluids may be made up of a combination of natural clays, water, caustic soda, and possibly barite,<sup>86</sup> and may contain significant amounts of suspended solids, emulsified water or oil.<sup>87</sup> However, testimony discussed below states that only non-toxic substances and fresh water are used for drilling fluids in the San Juan Basin.

After drilling, completion methods vary. “Open hole” completions contain a pipe which is perforated at the levels of the coal seams, but the area of the borehole surrounding the pipe is not filled with concrete. An open hole allows communication between aquifers, even when the aquifers have historically been separated by a non-permeable layer such as shale, because now an open hole exists between the two. If the space surrounding the pipe is filled with concrete, aquifers are much more protected from cross contamination.

During well stimulation, two different practices are used which can impact groundwater, hydraulic fracturing (“fracing”, pronounced “fracking”) and cavitation.



Fracing is the process of increasing formation permeability by injecting fluids at high pressures to cause the rocks to break. Some kind of solid material, usually sand, is injected with the fluid in order to hold open the newly created fractures. Most of the fracing liquid is recovered after the operation is complete, but at least in one documented instance, the materials proposed for use in fracing are toxic, including benzene, polycyclic aromatic hydrocarbons, ethylbenzene, toluene, xylenes, naphthalene, methanol, sodium hydroxide, and MTBE.<sup>88</sup> In another case, sworn testimony that fracing and drilling fluids used in coalbed methane development in the Fruitland Formation contained only fresh water and non-toxic additives was presented before the Colorado Oil and Gas Conservation Commission.<sup>89</sup> The environmental community contends that large amounts of anecdotal evidence indicate that fracing has negatively impacted citizen's drinking water wells,<sup>90</sup> but the oil and gas industry responds that they've always done things this way, and that studies have shown there are no impacts to water supplies from hydraulic fracturing.<sup>91</sup> The United States Environmental Protection Agency is seeking to resolve this controversy by conducting its own "Study of Potential Impacts of Hydraulic Fracturing of Coalbed Methane Wells on Underground Sources of Drinking Water",<sup>92</sup> which is currently underway.

Cavitation is the process of creating cavities in the coal seam. The well in this case is an open hole completed in the coal seam, and compressors pump air or foam into

the well to pressurize the coal.<sup>93</sup> A valve is then opened, which depressurizes the well, causing a vacuum that breaks up the coal and surrounding rock so that gas can flow through the resulting fractures.<sup>94</sup> The cavitation process "creates a jet engine-like noise that lasts anywhere from a few minutes to 15 minutes and is done several times before the well is completed. Bits of rock or coal mixed with water often spew out of the wellhead. Cavitation is a similar phenomenon to opening a shaken pop bottle, only on a much larger scale. Environmental and safety precautions are required during the process."<sup>95</sup> During cavitation, the rock is fractured under high pressure, which can cause fractures that allow water migration into other aquifers. In addition, if the formation is pressurized using foams, contaminants can be introduced into the groundwater.

Once the well is drilled and fracing or cavitation is completed, production begins. The wellhead is connected by pipeline to a distribution network, and a pumpjack is installed to begin removing water from the coal seam. Some wells require very little water removal to release the gas from the coal, and other wells produce water at rates of up to 2000 barrels of water per day.<sup>96</sup> The average in the San Juan Basin as a whole is 25 barrels per day, at a ratio of 0.013 gallons of water per every thousand cubic feet of gas produced.<sup>97</sup> One barrel equals 42 gallons, so the average well in the San Juan Basin produces 1050 gallons of water each day. For the 4,208 coalbed methane wells in the San Juan Basin, this adds up to 4.42 million gallons of water produced from the Fruitland Formation Coal in the San Juan Basin *every day*. This nearly 600,000 cubic feet of water is equal to 13.6 acre-feet of water per day.

✓ This produced water is in many cases as salty as the ocean, and therefore disposal of this water can be problematic. Total dissolved solids (tds) is a measure of the "saltiness" of the water, or the amount of dissolved sodium, calcium, chloride, and other elements. The tds of produced water results from a combination of factors: the depth of the coal beds; the type of the rocks surrounding the coal beds; the amount of time the rock and water are in contact; and the origin of the water entering the coal beds (*i.e.* is it fresh rainwater recharge or from another aquifer hosted in rock with a high calcium carbonate content).<sup>98</sup> In the San Juan Basin, the majority of the produced water has a total dissolved solids value of 2,000 parts per million (ppm) to over 20,000 ppm. For reference, drinking water



FIGURE 18 Photograph of unlined reserve pit at recently completed coalbed methane well, New Mexico portion of San Juan Basin. Black stain on dirt berm is from spray out of hole during cavitation (see below).



must contain less than 500 ppm tds, and seawater averages 35,000 ppm tds.<sup>99</sup>

Four methods of handling produced water are typically used today. One is storing produced water in large tanks onsite, which requires regular visits from water trucks, which pump the water from the tanks to the truck, and then transport the water to a wastewater treatment facility. Second, produced water may be reinjected into deep aquifers. Reinjection requires an aquifer with enough volume to hold the injected water and no communication with the ground surface or other aquifers. Third, produced water can be stored in onsite impoundments for evaporation. Finally, in some instances where the produced water has a low enough salinity, a permit may be issued for surface discharge. In the Colorado portion of the San Juan Basin, a controversial surface discharge permit was issued by the state, which would have allowed the JM Huber Corporation to discharge of up to 576,000 gallons of wastewater containing the equivalent of 8 tons of table salt *daily* from two gas wells.<sup>100</sup> The original permit would have allowed the dumping of this water into an irrigation ditch that drains directly into the Florida River, which then crosses into the Southern Ute Indian Reservation.<sup>101</sup> The state has admitted it erred in granting the original permit because they did not take into consideration the proper water standards for disposal, and has revoked the permit.

Problems exist with all of these disposal methods. Produced water often leaks from storage tanks, which are required to have a dirt containment berm surrounding them. The berms are often breached themselves, in which case the produced water flow can flow out of the berm and across the ground surface, as shown in Figure 19.<sup>102</sup> The white material outside the berm consists of salts that have precipitated from produced water spills that overtopped the berm. A rancher in the New Mexico portion of the San Juan Basin, a member of a BLM/rancher working group formed to address the impacts of gas development on grazing leases on BLM lands in New Mexico, says that at least 75% of the produced water tank berms on his BLM grazing lease show salt stains from produced water spills.<sup>103</sup> In addition, several spills that have escaped the berms have permanently impacted the surrounding soil, rendering it unfit to grow forage for his cattle. Finally, this rancher has expressed concern about what happens when the well's lifespan is over and the

area is reclaimed—is the salt-encrusted dirt considered waste to be hauled off and treated, or will it remain in situ, forever barren of vegetation?

Reinjection of produced water can introduce saline water into deeper aquifers that may contain fresher water. Often, an area with coalbed methane development does not have aquifers meeting the requirements for reinjection within the area. This is the case in the Powder River Basin. Or, if aquifers with the right characteristics are present, they might be in communication (*i.e.* water flows freely between them) with the coalbed aquifer. If the reinjection is rewatering the coal seam while pumps are dewatering the coal seam, the process becomes self-



FIGURE 19 Photograph of produced water spill next to produced water tank. White is salts precipitated from produced water. Photo courtesy T. Blancett.

defeating. In addition, pressurizing deep aquifers may cause unforeseen problems at the surface miles away from the actual injection point. One example is occurring in La Plata County, Colorado, where water is being injected into the Entrada Formation at considerable depth in the San Juan Basin.<sup>104</sup> However, the Entrada is folded upward at the northern end of the basin and comes to the surface north of Durango, Colorado. Where it comes to the surface new water seeps are occurring, most likely from the extra pressure in the formation caused by produced water injection at depth.

Surface impoundments also have problems. First, a surface impoundment requires digging up an even larger area of ground than was required by the well pad. In the Powder River Basin these ponds may reach areas as great as five acres.<sup>105</sup> Second, depending on water quality, these



ponds must be lined. As a result, disposal happens only by evaporation, and the water in the ponds gets successively more saline as evaporation proceeds. Wildlife or livestock drinking this water can become sick or even die from the saltiness. Third, as with any artificial impoundment, breaches or leaks can occur, spreading the salty water over the land surface and impacting both surface and groundwater supplies (see Figure 18). However, successful experimental testing by Amoco in the San Juan Basin using surface impoundments to treat produced water by using the natural freeze-thaw/evaporation process may lead to commercial use in reducing the volume of produced water requiring disposal.<sup>106</sup>

Finally, assuming the water quality is good enough, produced water can be discharged onto the ground surface. This causes problems with erosion of stream channels, flooding of low-lying areas, and other downstream effects. But, there can be beneficial uses to surface use and/or discharge of good quality produced water, including irrigation, livestock watering, creation of ponds for recreation or wetlands for habitat, dust suppression on roads,<sup>107</sup> and emergency firefighting.<sup>108</sup> One landowner in the La Plata County, Colorado, portion of the San Juan Basin (which contains the "freshest" water in the basin) even filed for and obtained the right from Water Court to use produced water for irrigation.<sup>109</sup> However, these benefits last only as long as the well remains in production. The majority of water in the San Juan Basin, however, is too salty for surface use. In La Plata County, more than 90 percent of produced water from oil and gas production is disposed of or used for enhanced recovery by underground injection.<sup>110</sup> Some of the remaining produced water is disposed of in evaporation pits, which are regulated, permitted and checked by the Colorado Oil and Gas Conservation Commission,<sup>111</sup> while some is pumped into produced water holding tanks and trucked to disposal facilities.<sup>112</sup>

#### GAS SEEPAGE INTO DOMESTIC WATER WELLS

Anecdotal evidence suggests that improperly sealed gas wells can allow gas to escape into shallow aquifers that are used for domestic well supplies. Documented evidence for coalbed methane production allowing the release of methane in domestic water wells occurred in the Colorado portion of the San Juan Basin in the early 1990s.<sup>113</sup> Older, conventional gas wells that had been completed open hole were blamed for a series of methane seeps. The

explanation that was finally developed is that dewatering the Fruitland coal seam for coalbed methane development dewatered the coal seams within the open holes of the conventional wells, allowing methane to escape both up the wells into shallow aquifers and along the formation to where the formation outcrops at the surface, filling basements and other enclosed structures with explosive levels of methane. Once this problem was identified, the conventional wells were recased and recemented, and other wells were plugged. Currently, a large scale monitoring program is in place to test well integrity and local water wells.<sup>114</sup> A Bradenhead valve exists on each gas well to monitor gas pressure in the wellbore, and the valve pressure is recorded every year. If there is any pressure, it is assumed to be from gas that has not been collected into the pipe. More than five pounds of pressure in a critical area, or twenty five pounds of pressure in a noncritical area, requires additional study of wellbore integrity.<sup>115</sup>

In addition, local water wells are tested before any coalbed methane wells are drilled in the area, then are tested one year after drilling, and at 3 year intervals after that, and the results are shared with the well owner. Methane concentrations greater than 2 milligrams per liter require additional chemical analysis to determine the source of the methane contamination.<sup>116</sup>

#### EFFECTS AT THE OUTCROP—DYING VEGETATION AT THE FRUITLAND OUTCROP, GAS SEEPS, COAL SEAM FIRES

"The Outcrop" refers to the area where the Fruitland Formation is exposed at the surface, which defines the outline of the coalbed methane-producing portion of the San Juan Basin. It is thought that dewatering the coal seam at depth is producing unforeseen effects where the coal outcrops at the surface. This includes gas seeps that may be causing vegetation to die off, and fires in the coalbeds at the surface. The BLM states that "exacerbation of these seeps and fires appears to be increasing as coalbed methane gas extraction increases and large-scale withdrawal of coalbed produced water intensifies."<sup>117</sup> Some industry representatives dismiss these concerns as being unrelated to coalbed methane development,<sup>118</sup> while others agree that dewatering the coal seam does exacerbate fires.<sup>119</sup> The environmental community contends that anecdotal evidence should be considered when planning for expansion of development.<sup>120</sup> Five under-



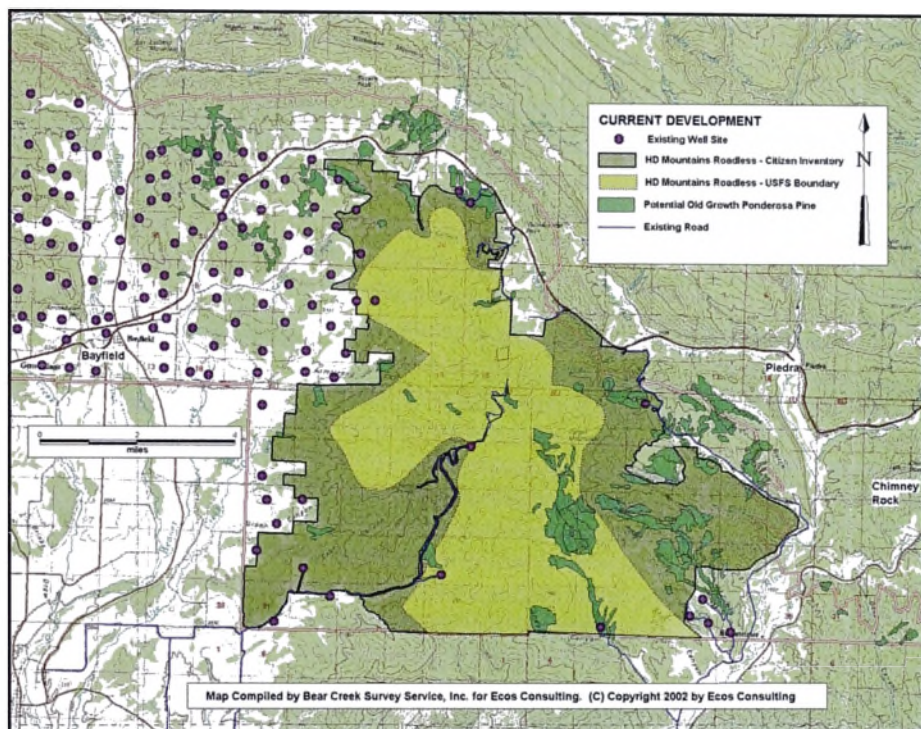


FIGURE 20 HD Mountains roadless area, current development, showing originally inventoried roadless area, surrounding inventoried roadless area, old growth Ponderosa pine, and current oil and gas development (purple dots). Note town of Bayfield, Colorado, to west of HD Mountains.

ground fires are currently burning on the Southern Ute Indian Reservation where Fruitland coal seams are exposed at the surface, but they are not currently a threat to public safety.<sup>121</sup>

#### HD MOUNTAINS ROADLESS AREA

The HD Mountains is a 39,000 acre roadless area in the extreme northeastern portion of the San Juan Basin in Colorado. The coalbed methane industry wishes to extract gas from the roadless portion of the HD Mountains region by drilling up to 100 new wells, and various citizen groups favor designation of the HD Mountains as a Roadless Wilderness. Current coalbed methane production in the HD Mountains area is limited to about two dozen wells that exist on land immediately adjacent to the roadless area or along two preexisting roads within the roadless area (see Figure 20). The roadless area is currently leased by three different gas companies, and as the situation stands now, industry has the right to develop the leases if they can demonstrate they are not violating the current laws,<sup>122</sup> pending the results of the Northern San Juan Basin EIS. Figures 20 and 21

(foldout maps) show the current and proposed development in the HD Mountains.

The HD Mountains contain some of the last remaining stands of unlogged, old-growth ponderosa pine in the San Juan Mountains.<sup>123</sup> The 6,193 acre Ignacio Creek area of the HD Mountains has been proposed as a Research Natural Area because of its pristine condition.<sup>124</sup> The HD Mountains are used by many different groups of recreational users, including hikers, horseback riders, hunters,<sup>125</sup> and mountain bikers. The bulk of the roadless area can be reached by the roads that currently exist along the edges. Plus, there is an existing trail system in the Sauls Creek area that was developed by the Columbine Ranger District. The scenic beauty of the old growth forest and quiet solitude of so much land uncrossed by roads are a major draw to recreationalists.

#### IMPACTS ON WILDLIFE

Roads and other development cause destruction of habitat as well as habitat fragmentation, which occurs when roads and other infrastructure are introduced into an area. Remaining habitat scattered in isolated patches, which increases edge to area ratio and leads to the loss of "core area", or prime species habitat.<sup>126</sup> Specific edge effects for forest environment fragments include "micro-habitat alterations, increased wind, more direct sun, dryer conditions (soil), more dramatic fluctuations in temperature, hotter midday, cooler at night."<sup>127</sup> Habitat fragmentation also favors certain species (i.e. deer, raccoons, skunks, blue jays) over others, and allows access to forest interior by edge species.<sup>128</sup> In addition, development affects wildlife migration routes.

The HD Mountains provide prime habitat for bald eagles, mule deer, elk, turkey, bear and the rare Mexican spotted owl.<sup>129</sup> The HDs are so important as winter range for wildlife that the United States Forest Service closes the few publically accessible roads during the winter



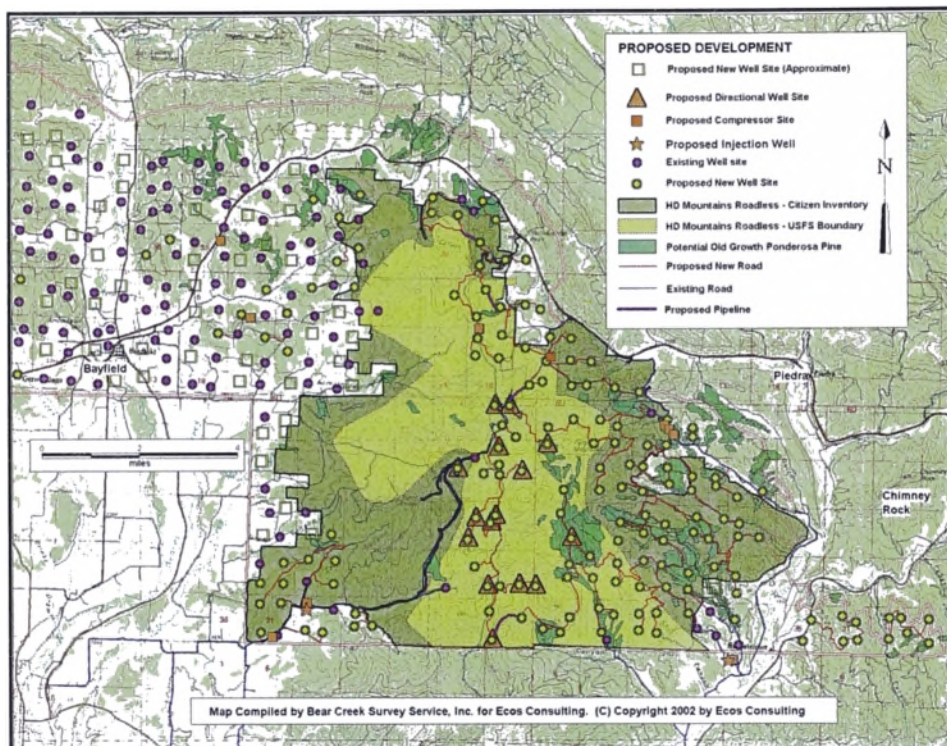


FIGURE 21 HD Mountains roadless area, proposed development, showing original inventoried roadless area, surrounding inventoried roadless area, old growth Ponderosa pine, and current (purple dots) and proposed oil and gas development (yellow dots, lines, triangles, squares).

so that the winter range is not disturbed.<sup>130</sup> The HD Mountains are a main elk and deer migration habitat, and drilling will “disrupt the migration and scatter the herds,”<sup>131</sup> which is of great concern to hunters and others concerned about the effects of development on wildlife.

#### ARCHAEOLOGICAL RESOURCES

Areas of archaeological significance exist in several places in the San Juan Basin. The Spring Creek Archaeological District encompasses the majority of the HD Mountains Roadless Area in Colorado. The district was listed on the National Register of Historic Places (NRHP) on May 21, 1983.<sup>132</sup> The roadless portion of the HD Mountains contains at least 100 ancient, undamaged pre-Puebloan cultural sites.<sup>133</sup> The NRHP designation

*provides recognition that a property is significant to the Nation, the State, or the community and assures that Federal agencies consider the historic values of the property in the planning for Federal or Federally assisted projects. In addition, listing in the*

*National Register ensures that significant archeological resources become part of a national memory.*<sup>134</sup>

In addition, the HD Mountains are sacred to the Southern Ute Indian Tribe, and in fact extend southward on to the SUIT reservation. The tribal council has voted in the past not to allow development in their portion of the HDs in order to protect the resource.<sup>135</sup>

In the New Mexico portion of the San Juan Basin are three areas with set aside to protect archaeological resources: Chaco Culture National Historic Park, Aztec Ruins National Monument, and Salmon Ruins & Heritage Park. Aztec Ruins was listed in the NRHP in 1966. Aztec Ruins is considered to be an outlier to the Chaco Canyon culture, and on December 8, 1987, the United Nations Educational, Scientific, and Cultural Organization designated Chaco Culture National Historic Park as a World Heritage Center, and included Aztec Ruins as a star in the Chaco outlier constellation.<sup>136</sup> In addition to these protections, measures to reduce noise around other highly visited archaeological sites are currently in progress.<sup>137</sup>



FIGURE 22 Photograph of ruin in Owl Creek, Utah, similar to those found in the San Juan Basin.



## RANGELAND IMPACTS

BLM lands in the New Mexico portion of the San Juan Basin are extensively leased for grazing, and some families have held their leases for several generations. These ranchers are in favor of multiple use of the land, however, many have found themselves in the unlikely position of siding with the environmental community when it comes to coalbed methane development on their grazing leases. Increased development threatens the health of the land as well as the health of their cattle. As more well pads are cut, more surface vegetation is destroyed. A typical well pad with associated connecting roads and pipelines can destroy three acres of forage,<sup>138</sup> and if this acreage is not properly reseeded, it can be particularly devastating to ranchers during drought years, and can lead to the need to overgraze other areas of the lease. In addition, improperly fenced produced water berms or reserve pits can give cattle access to drink polluted water (Figure 23). If a cow is found dead near one of these, the onus is on the rancher to prove that the cow died because of drinking the polluted water, adding additional expense to often marginal ranching operations.

## AIR QUALITY

Coalbed methane development impacts air quality in several ways. Higher levels of particulate matter are released when increased road building and well pad construction strips off protective topsoil, leaving bare dirt exposed to wind. Vehicle traffic on these roads contributes further to particulate emissions (see Figure 24). Emissions from vehicles and diesel powered generators also affect the air



FIGURE 23 Photograph of cow in poorly fenced, unlined reserve pit, BLM land, northern New Mexico. Photo courtesy T. Blancett.

quality surrounding coalbed methane developments. The combined effects of these emissions can affect both the local and regional air quality and visibility, and may impact nearby areas that have protected airsheds, such as Indian reservations and National Parks.

## NEW TECHNOLOGY AND BEST PRACTICES

### INTRODUCTION

The exploitation of coalbed methane as a resource has depended on the continuing development of new technologies to manage the issues unique to coalbed methane development. These technologies include different drilling options that allow multiple wells from a single pad, draining a larger area with less surface disturbance. However, before a well is drilled, the coalbed methane companies can take steps to reduce surface impact (and development costs) by minimizing the number of dry holes drilled. There are also procedures during the production phase that can reduce the impact to the surface and surrounding communities.

### EXPLORATION AND DEVELOPMENT BEST PRACTICES

The surface impact of coalbed methane development can be minimized at any step from the initial selection of a drill site, through drilling and well stimulation, to regular operation and maintenance. Best practices for selecting drilling targets include a detailed study of the area's geology using a combination of gravity and magnetic (geophysical) surveys, study of satellite images, and detailed study of the field geology in order to minimize



FIGURE 24 Drill rig near Carlsbad, New Mexico. Blowing dust is from vehicles driving on well pad and connecting roads.



the drilling of dry holes and the unnecessary clearing of well pads and roadways.<sup>139</sup> The field geology study includes studying coal at the surface to discern what might happen at depth; mapping fracture patterns; and knowing the microgeology of the coal seams, including gas content, using cores and surface samples. Once the drill site is selected, steps can be taken to mitigate surface disturbance during different phases of development. The initial clearing needs to be larger than the final well pad due to the amount of equipment required. As described above, best practices used during well drilling and stimulation can help minimize impacts to surface and ground water. Once the well is drilled, portions of the pad can be reclaimed and reseeded to help keep the bare dirt from blowing away and to contribute to grazing fodder. Trash and other drilling debris should be hauled away at this time. Any waste/reserve pits should be securely fenced and closed according to the stipulations in the application for permit to drill.

Several steps can be taken during production to reduce the impact on the surrounding land. Companies can use satellite telemetry to monitor well production, rather than having a worker visit the site every day. On site management of produced water, rather than offsite disposal, also reduces truck traffic to the well site. Compressor noise can be mitigated using barrier and other muffling devices. Equipment can be fenced to prevent people and animals from accessing onsite hazards.

#### DIRECTIONAL DRILLING

Directional drilling refers to an advanced drilling technique that deviates from the straight and vertical. According to the US Department of Energy (DOE), oil and gas wells have traditionally been drilled vertically at depths of a few thousand feet to as deep as 5 miles. Depending on subsurface geology, technological advances now allow wells to deviate from strictly vertical orientation by anywhere from a few degrees to completely horizontal, or inverted toward the surface.<sup>140</sup> The three categories of advanced drilling technologies recognized by DOE are directional, horizontal, and multilateral. These three techniques are illustrated in Figure 25. According to DOE, "directional and horizontal drilling enable producers to reach reservoirs that are not located directly beneath the drilling rig, a capability that is particularly useful in avoiding sensitive surface and subsurface environmental

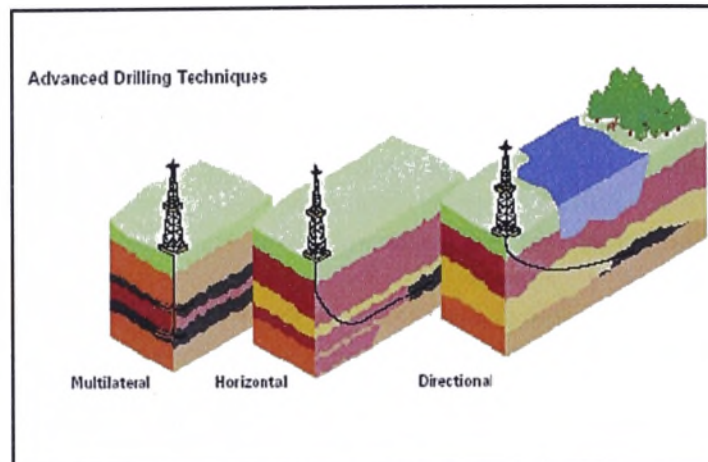


FIGURE 25 Schematics showing advanced drilling techniques: directional, horizontal, and multilateral.<sup>142</sup>

features. New methods and technologies allow industry to produce resources far beneath sensitive environments and scenic vistas in Louisiana wetlands, California wildlife habitats and beaches, Rocky Mountain pine forests, and recreational areas on the Texas Gulf Coast."<sup>141</sup>

In addition to enabling producers to dig beneath sensitive surface areas to reach remote reservoirs of oil and gas, horizontal drilling has been shown to increase resource recovery. DOE estimated that horizontal drilling could increase reserves in the US by 100 billion barrels of oil equivalent because the average production ratio is 3.2 to 1 for horizontal wells compared with vertical, while the average costs ratio is 2 to 1.<sup>143</sup> A horizontal well may produce at rates several times greater than a vertical well because it has an increased chance of intersecting natural fractures and increasing drainage of the nearby well.<sup>144</sup> Figure 26 shows how horizontal drilling can increase production by tapping into several producing regions at once.

Advances in directional drilling now allow extraordinarily precise control of drilling direction. Multiple wells directed at targets several miles distant can be drilled from a single location.<sup>146</sup> According to the National Petroleum Council, "More recent efforts in other parts of the world have extended the drilling reach to 5–6 miles."<sup>147</sup>

In multi-lateral drilling, multiple offshoots or laterals can radiate in different directions or contact resources at different depths from a single vertical wellbore.<sup>148</sup> Figure 27 shows an example of multi-lateral directional drilling being done in the Alpine Field in Alaska. According to DOE, this "21<sup>st</sup> Century Technology" will allow for



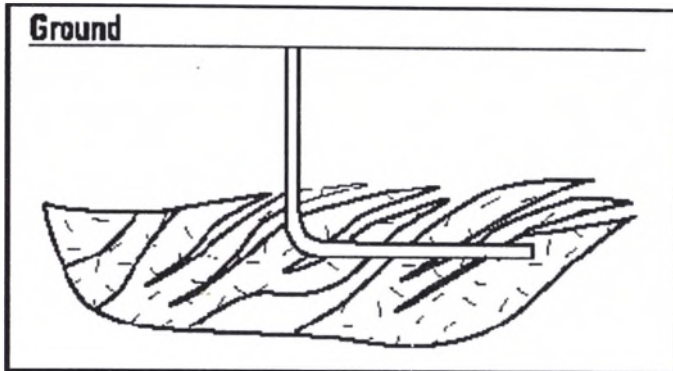


FIGURE 26 Example of horizontal well tapping into several producing reservoirs in a complex field where producing strata and non-producing strata interweave.<sup>145</sup>

smaller surface production pads and larger areas explored under the earth.<sup>149</sup> Using directional drilling technology, it is possible to develop nearly 80 square miles of subsurface area from a single 2-acre drill site.<sup>150</sup>

According to DOE, the environmental benefits of directional drilling include:

- Fewer wells
- Lower waste volume
- Protection of sensitive environments.<sup>151</sup>

#### FEASIBILITY AND CURRENT APPLICATIONS OF DIRECTIONAL DRILLING

Despite the present Administration's enthusiasm for directional drilling as a future energy solution, it seems to be more widely embraced and practiced by industry in other regions than in the San Juan Basin. Directional drilling is most commonly used when environmental concerns, space constraints, or other resource interests prevent vertical drilling from being implemented. When directional drilling has been proposed as a means of meeting No Surface Occupancy stipulations, such as in the HD Mountains, oil and gas producers often claim that directional drilling is too costly or infeasible in these locations. For example, the La Plata (County, Colorado) Energy Council, an oil and gas industry group says:

*There are limits to the degree that the well bore can deviate from the vertical and to the horizontal distance from the well surface site. Moreover, the limit of horizontal distance is affected by many factors, including the depth and the characteristics of the rock formations to be penetrated. The considerable additional*

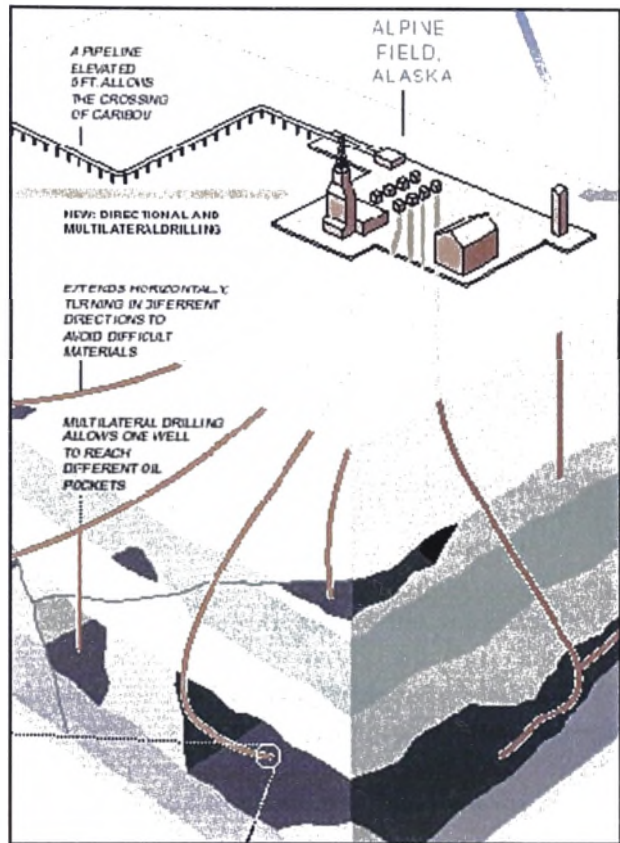


FIGURE 27 Schematic of the Alpine Field, Alaska, located about 60 miles west of the Trans-Alaska pipeline, showing multilateral drilling allowing one well to reach different pockets of oil.<sup>152</sup>

costs and increased risks of directional drilling must also be factored into the decision whether to utilize this technology.

Additional time to drill and complete well construction and increases in long-term maintenance activity sometimes necessary in a directionally drilled well, are surface impacts seriously considered before using this technology. Directional drilling can significantly increase well construction time, which includes drilling — turning a week's activity into a month or more. Increased long-term maintenance may result in frequent and repeated use of construction equipment, such as rigs, and associated noise at a directionally drilled well site. Further, it may be necessary to use additional equipment to draw gas out of a directionally drilled well, such as a pump jack. Thus, while directional drilling might appear to be less intrusive, in some cases the opposite will be true.<sup>153</sup>

However, directional drilling is becoming more common throughout the US. According to DOE, "At any given time, horizontal drilling accounts for 5 to 8% of U.S. land well count."<sup>154</sup> BLM managers for the San



Juan and Permian Basins report that directional drilling has been completed in both of the basins. Bill Papich, PR Director for BLM office that manages oil and gas development in the San Juan Basin, reports that there has been directional drilling done near Navajo Reservoir and under the towns of Farmington and Aztec, New Mexico.<sup>155</sup> In addition, horizontal drilling is currently being used for coalbed methane production in the San Juan Basin. Meridian Oil, Inc., used horizontal drilling to reach a coal bed methane resource in the Fruitland Formation. The completed well produced at a rate of 7 million cubic feet per day, as opposed to the average conventional rate of 1.05 million cubic feet per day.<sup>156</sup> CDX Technologies is also using horizontal drilling for coalbed methane development in the San Juan Basin. Their "Pinnate" technology allows them to drain areas as large as 1000 acres from one main well bore on a well pad smaller than is required by conventional wells. However due to limitations currently in place from the Colorado Oil and Gas Conservation Commission and infrastructure capacity, CDX's one horizontally drilled well in La Plata County is currently draining just 320 acres.<sup>157</sup> Additionally, a new way of developing coalbed methane has been proposed by the Omega Oil Company in Gillette, Wyoming, for their leases in the Powder River Basin.<sup>158</sup> From a single 7-acre pad, they propose to drill a vertical shaft to the coal seam and then drill horizontally in order to drain 8,500 acres of the coalbed. This approach would drain the same acreage as 220 conventional surface wells in the Powder River Basin, or 53 wells in the HD Mountains, half of the total number proposed. A few locations of this type of development, if located just outside the exterior boundary of the roadless area, could tap much if not all of the entire roadless area without requiring any new roads. Industry officials, however, plan to start development using conventional vertical wells, and expect that directional drilling might be necessary to deplete the coalbed methane resource in the HD Mountains.

The feasibility of directional drilling depends on several factors including:<sup>159</sup>

- **TYPE OF ROCK:** The Austin Chalk field has been the site of over 90% of the onshore horizontal rig count since the late 1980s and still accounts for the majority

of horizontal permits and rig activity in the US today. About 30% of all U.S. reserves are in carbonate formations.<sup>160</sup>

- **TYPE OF WELL:** Up until recently, most directional drilling was completed for oil wells. However, with the increase in gas drilling activity and the advent of coal bed methane recovery, the number of directionally drilled gas wells is increasing each year.
- **FLEXIBILITY OF DRILL PIPE:** the radius of the curve that can be drilled is determined in part by the flexibility of the drill pipe. For tight radius drilling, short sections of straight pipe must be used. A new options is flexible coiled piping which eliminates joints and allows for tight radius drilling.
- **TRAINED PERSONNEL:** Directional drilling is made possible by the convergence of several technologies in exploration and drilling including new diamond drill bits, computer drill control and laser guidance systems, and skilled personnel to implement all of these new technologies. The greatest barrier to directional drilling at the moment is the availability of trained personnel to operate all of these new technologies.

#### COST OF DIRECTIONAL DRILLING

Directional drilling can cost anywhere from 25% to 300% more than a vertical well to drill and complete.<sup>161</sup> However, these additional costs can offset by higher production rates and lower waste removal and reclamation costs. Furthermore, directional or multilateral drilling could eliminate costs to drill, maintain, and reclaim additional wells. Drilling expenditures for gas wells and horizontal wells in 2000 are shown in Table 3.<sup>162</sup> This table shows that horizontal wells averaged twice the cost of gas wells, but only 35% more per foot drilled. According to API, "advances in technology have made horizontally drilled wells a viable option for field development. Horizontal wells can improve productivity, enhance reservoir maintenance, or produce reservoirs which would be uneconomical with vertical wells."<sup>163</sup>

One example of the estimated cost premium for directional drilling in Colorado was reported by Barrett Resources Corporation. Barrett requested permission to increase well density in a natural gas field in Garfield County in western Colorado. Opponents including landowners and county officials suggested directional drilling as an alternative to drilling new wells. Ted



TABLE 4: API JOINT ASSOCIATION SURVEY OF DRILLING EXPENDITURES SUMMARY TABLE—2000

	Conventional Gas Well	Horizontal Well	Horizontal: Conventional
Average depth	5,470 feet	6,842 feet	1.25: 1
Average cost/well	\$756,939/well	\$1,300,000/well	1.72 : 1
Average cost/foot	\$139/foot	\$190/foot	1.37 : 1

Brown, Barrett's manager of engineering reported that the average cost to drill a vertical well in that location was \$1 million. Directional wells would cost as much as \$150,000 more to drill. Requiring 58 new wells, which collectively could produce about 96 billion cubic feet of natural gas, to be drilled directionally would add about \$8.7 million in project costs.<sup>164</sup>

Overall, directional drilling is touted as the 21<sup>st</sup> century method of drilling, especially when it is combined with 3-D seismic surveying. Costs for directional drilling are being reduced as it is being applied more frequently and more drillers are becoming familiar with the new technologies. The basis for the environmental benefits of oil and gas production as reported by DOE are advanced drilling and production techniques.<sup>165</sup> Many of the technological and cost barriers (if the full cost of production is considered) have been eliminated for directional drilling. Oil and gas industry reluctance to use directional drilling is primarily based on the increased drilling cost which must be borne by the wildcatter or production company. In order to overcome this barrier, the full field production cost must be evaluated. This evaluation will likely show that the increased drilling cost will be offset by increased production efficiency, reduced well maintenance, and a fewer number of wells being drilled, maintained, and reclaimed. Over the life of the field, directional drilling may actually be less expensive than drilling, maintaining, and reclaiming additional wells and well-sites.

#### NO<sub>2</sub>/CO<sub>2</sub> ENHANCED RECOVERY

The injection of carbon dioxide and/or nitrogen into coalbed methane reservoirs can greatly enhance gas recovery, from 30% to 400% above expected returns.<sup>166</sup> This technology can increase methane production rates up to six-fold, and increase "producible gas reserves" up to two-fold.<sup>167</sup> The injected gas displaces the methane in the coal, and some consider this to be the "ultimate methodology for extraction of this valuable resource."<sup>168</sup>

In fact, "coalbed methane reservoirs that might otherwise not be economical to develop under conventional production operations could become fully developed."<sup>169</sup>

Recovery of additional gas from the same well prolongs useful well life, reducing the need to drill additional wells in order to deplete the resource. Enhanced recovery via injection of gases has been tested in the San Juan Basin and found to be economically and technically feasible.<sup>170</sup> Using carbon dioxide for enhanced recovery has the additional advantage of disposing of a greenhouse gas with "virtually permanent storage capacity."<sup>171</sup>

### III: SAN JUAN BASIN COALBED METHANE DEVELOPMENT—SUMMARY OF TRADEOFFS

#### WHAT WE'VE LEARNED FROM HISTORY

The San Juan Basin is considered to be the "Granddaddy" coalbed methane basin. The first development started in the Basin in the late 1980's, and many of the technological advances that have spurred the further rapid development of other basins were initially tested and developed in the San Juan Basin. This includes understanding how methane is stored in coal, that removing water from the coal allows the gas to escape, and the role that natural fractures play in this process.<sup>172</sup> However, with new technology and understanding of the geology of coalbed methane leading rapid growth in well numbers, coalbed methane development has "raised a number of issues relating to the environment, permitting, and ownership."<sup>173</sup> Some of these issues have been easily resolved, while others still need to be addressed on a well-by-well basis.

One ongoing problem in the New Mexico portion of the San Juan Basin has been the lack of proper funding for BLM inspectors. According to former BLM Director Jim Baca, "inadequate staffing has made it difficult to inspect wells in the San Juan area and the number of wells out of compliance is astounding. Wells are not being properly maintained and water is not being properly



contained."<sup>174</sup> This problem has only gotten worse as the number of wells has increased.

### WHAT ARE THE CURRENT TRADEOFFS?

The tradeoffs of current coalbed methane development have been addressed throughout this paper. There is a delicate balance between protection of the non-energy resources development of the coalbed methane resource. There are many resources that have the potential to be negatively impacted by coalbed methane development, but there are also financial incentives rewarding development.

### BASED ON GOVERNMENT AND INDUSTRY PREDICTIONS, WHAT IS THE FUTURE SCENARIO?

Based on scenarios developed during the various EIS processes in different portions of the San Juan Basin, it is reasonable to expect that approximately 4000 more coalbed methane wells will be drilled in the Basin within the next 20 years. These wells would tap into a resource most often cited as 50 tcf of gas-in-place, which will most likely yield approximately 10 tcf given current technological and economic conditions (as discussed in Chapter 2). The takeaway capacity of the Basin, coalbed methane and conventional natural gas, will remain at approximately 4 bcf/day, most of which will continue to supply California's natural gas needs. With this continued and expanded development, it is the hope of area residents (ranchers, hunters, recreationalists, and the environmental community, among others) that the energy resource will be developed in a manner that minimizes impacts to the non-energy resources of the area, meaning using "best practices" in all stages of exploration, development, and production. This also means having a regulatory structure and staff in place with the resources to ensure compliance with environmental regulations.

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15. Cross section from case files of March 2000 infill drilling hearings, modified from figure created by Geologic Data Systems, Exhibit number 26, Cause No. 112, Docket No. 004-AW-05 and 06, La Plata and Archuleta Counties/Ignacio Blanco Field.

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17. The vast majority of the Fruitland Formation coal is buried too deeply to be recovered with current technology. If it could be recovered, it would be enough for approximately 185 years of US consumption at the current consumption rate of 1.08 billion tons per year (<http://www.eia.doe.gov/cneaf/coal/quarterly/html/t38p01p1.html>). Current U.S. recoverable coal reserves at producing mines is 18.34 short tons (1 short ton = 2000 pounds). The U.S. has a demonstrated reserve base of coal, potentially recoverable with current technology, of 507.2 billion short tons



(<http://www.eia.doe.gov/cneaf/coal/cia/html/t33p01p1.html>), about 280 billion tons of which are considered recoverable reserves ([ftp://ftp.eia.doe.gov/pub/pdf/international/0484\(2002\).pdf](ftp://ftp.eia.doe.gov/pub/pdf/international/0484(2002).pdf) figure 57, page 72).

18. As of December 31, 2000, U.S. operators had 177,427 billion cubic feet of dry natural gas reserves. Of that, 5.9% is in Colorado, and 9.8% is in New Mexico. Of the total U.S. proved reserve, 15,708 billion cubic feet, or 9%, is from coalbed methane. ([http://www.eia.doe.gov/pub/oil\\_gas/natural\\_gas/data\\_publications/crude\\_oil\\_natural\\_gas\\_reserves/current/pdf/ch4.pdf](http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/current/pdf/ch4.pdf) page 1 and 8).

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44. A note on terminology: "Infill Drilling" vs. "Downspacing": The current EIS is taking place because of the oil and gas industry's wish to change the number of wells per each 1 square mile, or section, from two to four. Each section contains 640 acres, so often this is expressed as a change from one well per 320 acres to two wells per 320 acres, or one well per 160 acres. However, there are two different ways that this process is being described by various groups—"Downspacing" and "Infill Drilling"—and some clarification is needed. According to Mike Weems (personal communication, January 29, 2002) of the Colorado Oil and Gas Conservation Commission (COGCC), the correct way to express what is being proposed is Infill Drilling. This term implies that drilling is occurring within the same lease as a previous well, keeping the divisions in order, and the "piece of the pie" within the drilling unit remains the same. Downspacing means cutting a drilling unit into smaller pieces. Based on royalty interests, it is important that this process is referred to as infill drilling.

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v. Uses above 30 tcf estimate and applies economically recoverable percentage at \$3.34/mcf

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From Potential Gas Committee, 2001, "Potential Supply of Natural Gas—2000: Rocky Mountain Area", in Decker, Michael K., 2001, *Potential Supply of Natural Gas in the United States, Report of the Potential Gas Committee December 31, 2000*, page 131. Published by the Potential Gas Agency, Colorado School of Mines, Golden, Colorado.

vii. Uses above 30 tcf estimate and applies economically recoverable percentage at \$2.00/mcf

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x. Uses PGC 10.24 tcf estimate and applies economically recoverable percentage at \$2.00/mcf

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